BEFORE THE ARIZONA CORPORATION COMMISSION

Commissioners

Tom Forese, Chairman
Bob Burns, Commissioner
Andy Tobin, Commissioner
Boyd Dunn, Commissioner
Justin Olson, Commissioner

REVIEW, MODERNIZATION, AND EXPANSION OF THE ARIZONA ENERGY STANDARDS AND TARIFF RULES AND ASSOCIATED RULES	DOCKET NO. E-00000Q-16-0289

JOINT STAKEHOLDER COMMENTS OF WESTERN RESOURCE ADVOCATES, THE ARIZONA UTILITY RATEPAYER ALLIANCE, DINÉ CARE, TO NIZHONI ANI, DINÉHÓZHÓ, THE TUCSON 2030 DISTRICT, THE NATIONAL ASSOCIATION OF ENERGY SERVICE COMPANIES, WESTERN GRID GROUP, THE CONSERVATIVE ALLIANCE FOR SOLAR ENERGY, EFFICIENCY FIRST, THE SOUTHWEST ENERGY EFFICIENCY PROJECT, PHYSICIANS FOR SOCIAL RESPONSIBILITY - ARIZONA CHAPTER, AND VOTE SOLAR

Western Resource Advocates (WRA), the Arizona Utility Ratepayer Alliance (AURA), Diné CARE, To Nizhoni Ani (TNA), DinéHózhó, the Tucson 2030 District, the National Association of Energy Service Companies (NAESCO), Western Grid Group, the Conservative Alliance for Solar Energy (CASE), Efficiency First, the Southwest Energy Efficiency Project (SWEEP), Physicians for Social Responsibility - Arizona Chapter, and Vote Solar appreciate the Commission's leadership in moving Arizona toward a cleaner, more modern, and resilient electric grid. We broadly support the clean energy resource provisions outlined in Commissioner Andy Tobin's *Energy Modernization Plan*, including increased investments in renewable energy, energy storage, energy efficiency/demand side management (DSM), and electric vehicles. By investing in these technologies, the Commission can reduce ratepayer exposure to fossil fuel price risks, costs, and potential future stranded assets, while reducing water usage and air pollution. Based on our initial analyses,[1] we expect that the *Energy Modernization Plan* is also cost-effective.

The *Energy Modernization Plan* has several critical components: expanded clean energy renewable resources, energy efficiency/DSM, energy storage, and electric vehicles; and the need for clean resources to meet peak demands and provide grid services. Each element or resource, on its own, will not achieve the broad goal of modernizing Arizona's electric sector, but taken together, they form a comprehensive roadmap and resource mix for Arizona's future electric grid.

[1] See the "Joint Stakeholder Comments on the Integrated Resource Plans of Arizona Public Service Company (APS) & Tucson Electric Power (TEP): Alternative Portfolios," February 2, 2018, http://images.edocket.azcc.gov/docketpdf/0000185642.pdf

For Arizonans to see the benefits of the *Energy Modernization Plan*, it is critical that Arizona's regulated utilities are directed to begin acquiring clean energy resources in the immediate near term. **Therefore, we encourage the Commission to establish interim, enforceable targets for clean energy resources, energy efficiency/DSM, energy storage, and electric vehicles. We encourage the Commission to work with stakeholders to establish appropriate interim targets.** In Table 1, we outline the clean energy, energy efficiency/DSM, and energy storage investments recommended for Arizona Public Service (APS) and Tucson Electric Power (TEP) in the Alternative Portfolios submitted by sixteen Joint Stakeholders[2] in the Integrated Resource Planning proceeding.[3] If expanded statewide, these targets are roughly consistent with the long-term goals of the *Energy Modernization Plan*. Adopting these interim targets would ensure the Arizona's regulated utilities are making incremental progress toward those goals. These targets should be refined as the details of the *Energy Modernization Plan* are defined. [4]

Table 1. Suggested interim targets for clean energy, energy efficiency/DSM, and energy storage for APS and TEP combined

Resource Type	2025 Goal – Total Resources Added after 2017	2030 Goal – Total Resources Added after 2017
Clean Energy Additions (Renewable Energy)	4,400 MW	6,800 MW
Tribal Clean Energy Commitment (as subset of renewable energy above)[5]	470 MW	580 MW
Energy Efficiency/ Demand Side Management (DSM)	1,600 MW	2,700 MW
Storage	1,100 MW	1,800 MW

The capacity values shown here are the amount of clean energy capacity added as described in the Joint Stakeholders' Alternative Portfolios, submitted in the Integrated Resource Planning docket, which roughly are similar to the levels proposed in the Energy Modernization Plan. Those capacity values in the Integrated Resource Planning docket reflect utilities' assumptions about forecasted load growth and large annual additions of distributed solar PV. The actual amount of clean energy acquired should be based on

[2] The Joint Stakeholders include: Western Resource Advocates (WRA), Arizona Utility Ratepayer Alliance (AURA), Diné CARE, To Nizhoni Ani, Western Grid Group, Arizona Interfaith Power and Light, Conservative Alliance for Solar Energy (CASE), Tucson 2030 District, Arizona Solar Energy Industries Association (AriSEIA), Efficiency First Arizona, National Association of Energy Service Companies (NAESCO), Solar Energy Industries Association (SEIA), Polyisocyanurate Insulation Manufacturers Association (PIMA), Arizona Community Action Association (ACAA), Southwest Energy Efficiency Project (SWEEP), and Our Mother of Sorrows Catholic Church.

[3] Ibid. at 1.

[4] We expect that these targets represent a floor for utility acquisition of renewables, energy efficiency/DSM, and energy storage, which would be exceeded if those clean resources become more cost effective.

[5] The tribal clean energy commitment is determined by two factors. The 470 MW through 2025 is equal to full utilization of transmission rights owned by APS and TEP on lines located on the Navajo Nation. The ~108 MW of tribal commitments from 2025 to 2030 is equal to the share of 500 MW of transmission rights that will be granted to the Navajo tribe at the end of 2019 that is proportional to the two utilities ownership stake in Navajo Generating Station (APS = 14% or 70 MW, TEP = 7.5% or 37.5 MW).

load growth determined and the technologies selected under the Energy Modernization Plan. The energy efficiency/demand side management targets above include the effects of programs and services and do not include the effects of rate design.

In addition, the *Energy Modernization Plan* also is in a unique position to support a transition to clean energy resources developed on tribal lands, particularly for Navajo and Hopi communities, which have a long history of providing energy resources in Arizona. **To that end, we also urge the Commission to adopt both near- and mid-term targets for clean energy resource development commitments on tribal lands, in order to take advantage of utilities' existing transmission capacity and to contribute to economic development that would provide a direct benefit to Navajo and Hopi tribal communities.**

The Commission should work with APS and TEP to secure commitments for 470 MW of clean energy developed on tribal lands by 2025, fully utilizing the rights to transmission capacity that the two utilities have on lines crossing the Navajo Nation. By 2030, the utilities should commit to adding another ~108 MW of tribal clean energy to their systems. This latter amount is equal to a share of the 500 MW of transmission capacity allocated to the Navajo Nation that is proportional to the two utilities' ownership shares in Navajo Generating Station. That allocation should be filled with clean energy destined for APS and TEP customers as part of the two utilities' obligations to the tribes after benefitting for decades from the power generated through Navajo and Hopi resources.

As part of its responsibilities to the Navajo and Hopi, the Commission should also work with APS and TEP to ensure that utility-related clean energy development occurs in balanced, culturally appropriate ways. The benefits of clean energy projects should flow both to the tribal governments and to local communities to create a diversity of revenue streams and job creation that are not concentrated in a single location with a single beneficiary. A percentage of power from projects must be made available to local communities to help electrify the nearly 20,000 Navajo homes that still lack electricity and indoor water. Culturally appropriate development will also require sensitivity to issues such as land-use impacts on traditionally important activities like grazing and agriculture and on sacred sites.

Below, we address the issues that the Commission Staff raised in its Notice of Inquiry.

1. Public Interest/Cost Benefit

In the following section, we address the Commission's questions about the potential cost impacts of the Energy Modernization Plan, changes to the resource mix, and potential stranded investments. Questions about specific issues, such as biomass, energy storage, and electric vehicles are addressed later in these comments.

The Commission, as it stated in its Notice of Inquiry, has the responsibility to establish reasonable rates for customers. As part of that responsibility, the Commission must evaluate and balance the cost of resources, risk and uncertainty, and the public interest. Electricity sources that rely on fossil fuels have higher risks due to fuel price uncertainty and future regulatory risks. The *Energy Modernization Plan* establishes goals for Arizona that would drive higher levels of renewable energy, energy efficiency/DSM, and energy storage than the major utilities have in their current plans. Because these resources do not rely on fossil fuels, they limit utilities' exposure to future fuel price risk, and associated risk of uneconomic (or stranded) assets. In addition, energy efficiency/DSM and most forms of renewable energy have no emissions and minimal water use, further minimizing risk. By mitigating these risks, the Commission can effectively mitigate future unforeseen cost impacts on customers.

Sixteen stakeholders (the "Joint Stakeholders")[6] recently submitted Alternative Portfolios in response to APS' and TEP's proposed Integrated Resource Plans. While not exactly aligned with the proposed *Energy Modernization Plan*, the Alternative Portfolios reflect a similar mix of resources[7]: They include significantly expanded investment in utility-scale renewables (in addition to the distributed solar that was in the utility IRPs), energy efficiency/DSM, and energy storage between now and 2032. The Alternative Portfolio analysis can provide insight into the *Energy Modernization Plan*'s impacts on customer costs, reliability, and stranded assets, each described in greater detail below.

Cost: The Joint Stakeholders analyzed the cost of the Alternative Portfolios and found that the portfolios reduced the net present value of costs, relative to the utilities' proposals, which focused more heavily on natural gas resources. Specifically, over the 15-year period evaluated, the Alternative Portfolio costs are shown below, alongside the costs of the utilities' proposed resource plans:

Table 2: Costs of the Joint Stakeholder Alternative Portfolios versus the APS' and TEP' preferred resource plans

Utility	Alternative Portfolio – NPV of Revenue Requirements (billions)	Utility's Proposed Plan – NPV of Revenue Requirements (billions)
APS (Flexible Resources Portfolio)	$25.6	$26.0
TEP (Reference Case)	$13.7	$14.0

More broadly, costs for renewable resources and battery storage have declined significantly in recent years. Lazard's *Levelized Cost of Energy Analysis* published in 2017[8] showed levelized costs for solar (thin film, utility-scale fixed axis projects) at $43-$48/MWh, and wind at $30-$60/MWh, before federal tax credits are considered. Recent RFPs have shown similarly low prices for renewables in the Southwest. PPA prices for solar PV in Nevada, Colorado, and Arizona have recently been reported in the $29-35/MWh range,[9] and the price for wind projects

[6] Ibid. at 2.
[7] A significant difference between the two is the *Energy Modernization Plan* includes and classifies nuclear power as clean energy. However, cost comparisons are still appropriate as both plans include existing nuclear - Palo Verde Generating Station.
[8] Lazard's Levelized Cost of Energy Analysis, Version 11,0, Lazard, November 2017, https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf
[9] See, for example, the following recent announcements: https://pv-magazine-usa.com/2017/11/09/nv-energy-seeks-approval-for-31-34mwh-solar-ppas/; https://www.utilitydive.com/news/xcel-solicitation-returns-incredible-renewable-energy-storage-bids/514287/; and

recently approved in New Mexico were reported in the $18-20/MWh range.[10] In Xcel Energy's recent RFP in Colorado, the *median* price for solar PV (single axis tracking) was $29.50/MWh, and the wind prices were $18.10/MWh.[11]

Energy storage costs have also fallen sharply in recent years. Lazard's 2017 *Levelized Cost of Storage Study*[12] estimates a levelized cost equal to $395/kW-yr for a 4-hour duration lithium-ion battery (including financing), based on an estimated capital cost of $1,338/kW for a battery system installed in 2017. Xcel Energy's recent RFP received bids for over 1,600 MW of stand-alone battery storage, with a median price of $11.30/kW-month, which, if available year-round, translates to $136/kW-yr. The bids received in Xcel's RFP included several large projects with up to 150 MW of capacity and up to 10 hours of battery storage. [13]

Meanwhile, energy efficiency resources remain significantly less expensive than other resource options both in terms of providing peak capacity ($/kW) and providing energy savings or supply ($/MWh). The table below compares the incremental costs of several supply side resources as reported in APS' Integrated Resource Plan and the actual incremental cost of energy efficiency programs as reported in APS' annual Demand Side Management (DSM) reports[14]:

Table 3: The low cost of energy efficiency/DSM compared with other resource options

Resource	$/kW, peak (installed costs)	$/MWh (fuel cost)	$/MWh (levelized total cost)
APS Incremental energy efficiency (2015)	$631	$0	$12
APS Incremental energy efficiency (2016)	$676	$0	$12
Large Frame Combustion Turbine	$759	$68	$230
Natural Gas Combined Cycle	$1,236	$39	$92
Aeroderivative Gas Turbine	$1,475	$63	$326

Reliability: Our preliminary analysis of the Alternative Portfolios indicates that the mix of renewables, energy efficiency/DSM, and energy storage would meet key reliability constraints on the utilities' systems. Specifically, the Alternative Portfolios had sufficient capacity to meet 10-minute and 3-hour ramping needs for TEP and APS, respectively. Our more detailed

https://www.utilitydive.com/news/updated-tucson-electric-signs-solar-storage-ppa-for-less-than-45kwh/443293/

[10] Hudson, David T., on behalf of Southwestern Public Service Company. Direct Testimony, New Mexico Public Regulation Commission, Case No. 17-00044-UT.

[11] Public Service Company of Colorado, December 28, 2017. 2016 Electric Resource Plan, 2017 All Source Solicitation 30-Day Report (Public Version).

[12] Levelized Cost of Storage 2017, Lazard, November 2, 2017, https://www.lazard.com/perspective/levelized-cost-of-storage-2017

[13] Public Service Company of Colorado, December 28, 2017. 2016 Electric Resource Plan, 2017 All Source Solicitation 30-Day Report (Public Version).

[14]APS 2016 and 2015 DSM Reports, APS 2017 Integrated Resource Plan Table 2-3 (p 49). APS 2017 Integrated Resource Plan Attachment D.3 – Generation Technologies (p 312). Energy efficiency (EE) program costs exclude demand response, behavioral efficiency, and prepay programs. EE costs are all portfolio costs, e.g. rebates and incentives; training and technical assistance; consumer education; program implementation; program marketing; planning and administration; measurement, evaluation, and research; and performance incentives. They do not include the customer contribution to EE measure costs.

analysis of APS' system showed the utility could manage the high levels of utility-scale renewables in future years without curtailing Palo Verde Nuclear Generating Station, even when distributed generation was high and total demand was low. While we did not perform a full dispatch model, our analyses indicate that the portfolio of resources proposed in the *Energy Modernization Plan* would not present unmanageable reliability challenges over the next 15 years. Furthermore, new technologies, such as electric vehicles, could alleviate some reliability concerns, particularly if electric vehicle charging is available and utilized during daytime hours, when solar PV generation is high.

Stranded Assets: The Alternative Portfolios can also be instructive in evaluating possible stranded assets. Over the 15-year period, the Alternative Portfolios retired existing power plants on the schedule proposed by Arizona's utilities, or when their fuel contracts end.[15] The Alternative Portfolios did not propose retiring or ending any contracts with existing gas plants over the 15-year period. While the Alternative Portfolios do not extend beyond the 15-year planning period, we expect that minimizing investments in new fossil plants in the near-term can minimize the risk of stranded investments over the long term.

Renewable Energy on Tribal Lands: In addition to evaluating utilities' cost and exposure to risks, the Commission's policies must also consider the public interest. For decades, Arizona utilities – both electricity and water providers – have relied on energy generated on Tribal lands, in particular the Navajo Generating Station (NGS) and coal from Hopi Tribal lands. While we agree with Arizona's utilities that NGS is no longer economic and should be closed at the end of 2019 as currently planned, we support continued cooperation between the tribes and the broader Arizona community in terms of their shared energy economy. APS and TEP customers have paid for transmission capacity that could be repurposed to deliver renewable resources from Navajo and Hopi lands to utility customers. Specifically, given transmission ownership, APS and TEP could develop and transmit 300 MW and 170 MW respectively of solar or wind energy generated on Tribal lands by 2025. This type of investment would certainly be in the public interest and support the Tribes' economic development efforts to replace lost NGS power plant and mine revenues.

In sum, the Commission should evaluate the cost *and the risk profile* of resources used to meet Arizona's energy needs. Our analysis of the Alternative Portfolios, developed in response to APS and TEP's resource plans, provides useful insight into the potential benefits of the *Energy Modernization Plan*.

2. Policy Framework

This section addresses the Commission's questions about which entities the Energy Modernization Plan should apply to and the role of natural gas generation. Specific questions about cost, reliability impacts, and stranded assets are addressed in the "Public Interest/Cost Benefit" section above.

[15] The Alternative Portfolio proposes to retire Four Corners in 2031, when other utilities have announced plans to exit the plant and when its existing coal contract ends; proposes to retire Cholla in 2024, when APS has proposed to exit the plant; and proposes to retire the San Juan Units 1 & 4 in 2022, when TEP and PNM have proposed retirement.

The proposed *Energy Modernization Plan* should apply to all utilities regulated by the Corporation Commission. As we outline in the "Public Interest/Cost Benefit" section above, the *Energy Modernization Plan* can provide significant benefits to those utilities and their customers, including cost savings and mitigation of future fuel price, stranded assets, and regulatory risk. The Commission has authority over APS, TEP, UniSource Electric, and Arizona Electric Power Cooperative, Inc., which represent approximately 55% of the electric sales in the state.[16] The Commission should move forward with implementing the *Energy Modernization Plan* for those utilities and their customers, so that those customers can enjoy the benefits of the Plan as soon as possible.

It is appropriate for the goals or rules established under the *Energy Modernization Plan* to apply to electric utilities' entire portfolio of energy resources, including utility-owned power plants and power purchase agreements (PPAs). One of the key benefits of the *Energy Modernization Plan* is reducing customers' risk and exposure to volatile fuel prices and regulatory risk – that risk exposure can apply to both owned resources and long-term contracts. Because we recommend adopting the *Energy Modernization Plan* for utilities within the Commission's jurisdiction, merchant power plants not serving regulated utilities would be excluded.

The *Energy Modernization* Plan does not – and should not – establish a role or target for natural gas generation. Today, combined cycle plants and combustion turbines provide specific services for utilities. For example, combustion turbines are used to meet peak demands and fast ramping needs. However, other technologies can provide similar benefits: batteries, for example, can be discharged to meet evening peak demands (regardless of when they are charged), and offer quick ramping capabilities. Additionally, wind plants with automatic generation control can provide faster response than fossil generation. As we note in our comments on energy storage, prices for battery storage have declined significantly; the bids received in Xcel Energy's recent RFP had a median price of $11.30/kW-month for standalone storage, a median price of $36/MWh for solar plus storage projects, and a median price of $21/MWh for wind plus storage projects.[17] Batteries offer an environmentally preferable, and possibly cheaper, alternative to combustion turbines. Similarly, demand response can be dispatched to address ramping needs at extremely low cost. And energy efficiency can be targeted to specific loads to achieve more savings during peak or ramping periods.

In sum, we urge the Commission to quickly develop and adopt enforceable requirements for electric utilities within Commission jurisdiction, in order to provide those utilities' customers the expected benefits of the *Energy Modernization Plan*. And, importantly, to ensure customers see those benefits in the near term, we recommend the Commission adopt interim targets. The table below reflects the levels of renewable energy, energy efficiency/DSM, and energy storage that were modeled in the Alternative IRP Portfolios submitted by the Joint Stakeholders; while this reflects only the resources added for APS and TEP's systems, it can provide starting point for establishing interim targets for all regulated utilities.

[16] U.S. Energy Information Administration, 2017. 2016 Utility Bundled Retail Sales- Total (Data from forms EIA-861 – schedules 4A & 4D and EIA-861S).

[17] Public Service Company of Colorado, December 28, 2017. 2016 Electric Resource Plan, 2017 All Source Solicitation 30-Day Report (Public Version).

Table 4. Suggested interim targets for clean energy, energy efficiency/DSM, and storage for APS and TEP combined

Resource Type	2025 Goal – Total Resources Added after 2017	2030 Goal – Total Resources Added after 2017
Clean Energy Additions (Renewable Energy)	4,400 MW	6,800 MW
Tribal Clean Energy Commitment (as subset of renewable energy above)[18]	470 MW	580 MW
Energy Efficiency/ Demand Side Management (DSM)	1,600 MW	2,700 MW
Storage	1,100 MW	1,800 MW

3. Clean Energy

The Commission has raised questions about the structure of a clean energy standard, how it relates to the renewable energy standard, what resources should be included, and potential water benefits of the standard. We address those questions and provide recommendations on implementing a Clean Energy Standard below. Attachment A includes several clean energy standard rules that have been introduced or adopted in other forums.

Defining a "Clean Energy Standard": The *Energy Modernization Plan* proposes to create a Clean Energy Standard (CES) for utilities. We support creating a CES, and recommend it exist alongside the Renewable Energy Standard (RES). We also recommend that it exist alongside an extended and expanded Energy Efficiency Resource Standard (EERS) (discussed further below). Notably, these three standards – a CES, a RES, and an extended and expanded EERS – accomplish different, but complementary goals.

- The RES advances renewable energy technologies, which provide important benefits such as reducing fossil fuel risks, increasing portfolio diversity, and reducing pollution.
- An extended and expanded EERS (one extended and expanded beyond 2020) would support continued investment in cost-effective DSM which promotes price stability, mitigates exposure to volatile fuel prices, limits unnecessary load growth, and creates cost savings opportunities for customers.
- A CES is a technology-neutral standard that requires utilities to adopt resources based on their emissions rather than their technology. Because a CES is technology neutral, utilities are able to adopt the most advantageous strategies or technologies for reducing

[18] The tribal clean energy commitment is determined by two factors. The 470 MW through 2025 is equal to full utilization of transmission rights owned by APS and TEP on lines located on the Navajo Nation. The ~108 MW of tribal commitments from 2025 to 2030 is equal to the share of 500 MW of transmission rights that will be granted to the Navajo tribe at the end of 2019 that is proportional to the two utilities ownership stake in Navajo Generating Station (APS = 14% or 70 MW, TEP = 7.5% or 37.5 MW).

emissions and can adapt as new technologies emerge or existing technologies are improved.

In this complementary manner, the RES and an extended and expanded EERS would establish a base amount of renewable energy and energy efficiency investment, respectively, and the CES would serve as a mechanism to support investments in these and other resources that reduce emissions of pollution.

States have defined Clean Energy Standards in various ways. Several existing or proposed rules provide useful references:[19]

- The **New Mexico Public Regulatory Commission** (PRC) is evaluating a Clean Energy Standard rule that was proposed to the Commission in August 2017 (included as Attachment A.1) by WRA, the New Mexico Attorney General, and Prosperity WORKS, a low-income consumer advocacy organization. The New Mexico CES would require regulated utilities to reduce their emissions 4% per year from 2012 levels, starting in 2019, and would achieve an 80% reduction in emissions by 2040. Utilities earn clean energy credits for their generators based on their emissions. Zero emission resources such as renewables and nuclear energy earn full credit, while natural gas and market purchases earn partial credits. Utilities retire those clean energy credits every three years to show compliance.

- Former **U.S. Senator from New Mexico Jeff Bingaman** introduced a **federal Clean Energy Standard Act of 2012** (included in Attachment A.2), which required utilities to meet 24% of their total load with clean resources in 2015 and increased that percentage annually to require 84% of their total load be met with clean resources in 2035. Senator Bingaman's proposal would award credits based on a generator's emissions intensity, where zero emission resources like nuclear and renewables earn full credit, and natural gas or biomass resources earn partial credits, depending on their emissions profile. Utilities comply with the standard by earning and retiring enough clean energy credits to meet the annual requirement. For example, under the proposed standard, in 2025, utilities were required to hold clean energy credits equal to 54% of their electricity sales.[20]

- **Massachusetts** established a Clean Energy Standard in 2017 which requires utilities to meet 16% of their retail sales with clean energy in 2018, increasing by 2% per year to 80% in 2050. In Massachusetts, "clean" sources of energy include any generators that have lifecycle emissions at least 50% lower than an efficient natural gas plant.[21] (See the factsheet included in Attachment A.3)

---

[19] Salt River Project also has a Sustainable Portfolio Plan that includes several types of clean energy resources in their plan, and also includes a "goal within a goal" for energy efficiency.
[20] The full text of the bill is available here: https://www.congress.gov/bill/112th-congress/senate-bill/2146/text
[21] Massachusetts 310 CMR 7.75: Clean Energy Standard. Fact Sheet available at http://www.massdep.org/BAW/air/3dfs-electricity.pdf. The rule has additional provisions on banking, location, eligible facilities and grandfathering.

- The **Bureau of Reclamation** adopted a Clean Energy Standard mechanism to reduce emissions caused by the **Central Arizona Project,** as part of the Technical Working Group Agreement for the future of Navajo Generating Station. The CES description, which is included as Attachment A.4, required the Central Arizona Project (CAP) to reduce the emissions associated with its energy usage by 3%/year, starting in 2015. To demonstrate compliance with this requirement, CAP was required to earn clean energy credits from eligible resources and retire those credits every three years. Credits were awarded based on a resource's emissions profile[22]: renewables, nuclear, and other zero-emission sources of energy earned full clean energy credits, while natural gas generation earned partial credits.

We recommend a CES in Arizona treat resources in the following way:

- The CES should be an additional and complementary policy that operates alongside the RES and an expanded and extended EERS (or in the alternative, interim, enforceable targets for renewable energy and energy efficiency). In this manner, the RES and EERS would establish a base amount of renewable energy and energy efficiency investment, respectfully, and the CES would serve as a complementary mechanism that supports investments in these and other resources that reduce pollution.

- The CES should avoid explicit carve-outs for particular energy or technology types. This allows all eligible resources to compete, and for utilities to adopt the lowest-cost, most cost-effective resource. If the Commission desires certain resources, it can evaluate those resources and direct the utilities to adopt them as part of a strengthened Integrated Resource Planning process (discussed further below).

- We recommend renewable energy and distributed renewable generation (DG) count towards compliance with the CES *if* the utility using these resources for compliance also holds and retires the Renewable Energy Credits (RECs) associated with them. If the utility does not acquire the RECs from a renewable resource, it is effectively forgoing the "clean" attributes of that resource – and allowing another entity to use the REC to comply with renewable energy or other clean energy requirements.

- Nuclear has no emissions of CO_2; therefore, it is an eligible resource for complying with a CES. However, it should not be considered a renewable technology under an RES or be eligible for RECs.

- Energy efficiency/DSM is valued under many forms of CESs, including the example policies described above. Because the clean energy required is tied to the utility's load in any given year, energy efficiency is essentially rewarded the same as any zero-emission resource, and a CES can therefore provide a strong impetus for efficiency/demand side management investment.

Implementation: We recommend the Commission move forward with workshops, a rulemaking, or other procedures to establish a CES for regulated utilities. Several features are critical to the

[22] The emissions profile is measured off of a generator's carbon intensity; CO2 emissions are a reasonable proxy for emissions of other pollutants, including NOx, SOx, and others.

effectiveness of a CES. First, we recommend the Commission adopt near-term, regular compliance obligations, which should begin as soon as a rule is promulgated. We recommend adopting a multi-year compliance window, which allows utilities compliance flexibility in order to account for annual variations in demand, generators' output, and planned outages. A CES should establish a system for awarding clean energy credits (CECs) to eligible clean resources. A system of credits is a key component of a market-based program, under which utilities can buy or sell credits from each other, reducing overall costs.

Finally, technology cost and performance may change dramatically over time. By developing a technology-neutral standard, the Commission provides the appropriate direction to utilities. Utilities, stakeholders, and the Commission can then evaluate and determine what resources are most cost-effective for meeting the standard.

Impacts of a Clean Energy Standard: A CES could provide important benefits to Arizona customers. As we described in the Public Interest/Cost Benefit section, the Alternative Portfolios submitted by the Joint Stakeholders in the IRP process illustrate valuable cost benefits for customers, in addition to reduced air pollution and water use. The water impacts of a "clean" energy portfolio depend on the energy sources used – energy efficiency uses no water (and, depending on the measure, may actually save water), solar PV and wind require no water, while solar thermal and nuclear plants can require more significant amounts of water, depending on the type of cooling technology employed. Palo Verde Nuclear Generating Station of course uses recycled wastewater.

In sum, we support developing a CES alongside and in addition to the existing RES and an expanded and extended EERS. As noted previously, the RES, an expanded and extended EERS, and CES accomplish different – but complementary – goals. We expect that, based on the modeling and analyses developed for the Alternative IRP Portfolios, that a higher level of renewables and energy efficiency/DSM investment would be critical resources utilized to meet a Clean Energy Standard, and would provide cost savings for APS and TEP customers.[23]

4. Clean Energy for Peak or Reliability Needs (Clean Peak Standard or Target)

This section broadly addresses the need for policy mechanisms that ensure clean energy investments meet system needs.

The goal of the *Energy Modernization Plan* is to create an energy system that is clean, affordable, *and* reliable. Renewable energy and DSM resources protect the environment and protect customers from the risk of fossil fuel price fluctuations, stranded assets, and regulatory risks. As such, it is critical that investment in these resources takes place to meet system and local reliability needs. More than just meeting "peak" demands, the bulk power system needs include a broader set of grid reliability services. For instance, establishing a "Clean Peak Target" may ensure renewables are generating energy during system peak – but may miss other key grid needs, such as enhancing grid reliability by making resources more flexible. Similarly, a Clean Peak Target established today may not provide the services needed in five or ten years,

[23] Our modeling did not analyze UNS or AEPCo's resource plans.

as grid needs and technologies change and the timing of the system peak or peaks differentiates and evolves (i.e. the timing of the distribution, transmission, and generation capacity peaks). While meeting system peak is certainly important, available technology provides new and varied options to reduce and shape peak energy use. Thus, concentrating on only peak energy is too narrowly focused. We encourage the Commission to take a broad look at policy options for ensuring that utilities provide reliable electric service at all times, including to meet the evolving needs of the local distribution system.

Electric grid demands are quickly evolving. To that end, a Commission regulation or goal should create future optionality, support the development of resources that can be used flexibly and set goals that can adapt as system needs evolve. Consider, for example, the following factors that will likely impact the Arizona grid over the coming decade:

- Peak demand in Arizona is shifting later into the day, changing the period of peak demands.

- As the utility system continues to change, it may experience different, separate, and distinct peaks for distribution, transmission, and generation capacity.

- Expanded regional energy markets may increase access to a more diverse mix of renewable resources, increasing bulk system reliability and reducing the need for new fossil resources generating at peak demand periods. For example, as Arizona solar generation declines in late afternoon, Wyoming wind may be increasing, meeting system reliability at lower costs.

- New technologies such as electric vehicles may change grid demands, and also may provide opportunities for demand response. Electric vehicle charging may create new secondary peak periods of demand or could be used to alleviate some of the "duck curve" issues. For instance, modeling suggests that high levels of electric vehicle adoption could create surges in demand mid-morning, when drivers arrive at work and begin charging, and again in the evening, when drivers charge at home,[24] whereas well-designed electric vehicle charging rates and ample, automated charging stations, as well as managed charging and demand response programs targeted to electric vehicles, can address and manage these charging patterns and incentivize motorists to charge when electricity is cheap and plentiful, such as when inexpensive daytime solar PV is available, and avoid charging at times of system peak demand.

- Challenging conditions do not always occur at peak loads. Days with light loads (such as in the spring) with over-abundance of inflexible baseload generation can be challenging and may not be addressed by a Clean Peak Standard.

In short, the changing electricity sector means that today's system needs are likely not to be the same as system needs five or ten years from now. Furthermore, a Clean Peak Standard should include demand response and energy efficiency and should account for local reliability needs

[24] See, for example, Figure 4.3 of Bedir, Abdulkadir, Noel Crisostomo, Jennifer Allen, Eric Wood, and Clément Rames. 2018. California Plug-In Electric Vehicle Infrastructure Projections: 2017-2025. California Energy Commission. Publication Number: CEC-600-2018-001.

and distribution system upgrades. DSM resources can be developed and deployed to meet peak demand and ramping or other operational needs. Additionally, through energy efficiency and demand response, future optionality is increased as demand can later be adjusted to match evolving patterns of resource availability and costs.

The Commission has several options for ensuring that clean energy – including renewables and energy efficiency/DSM - also meets the system's peak demands and reliability needs. Policy tools include the following:

- **Clean peak target** – this may achieve the goal of requiring clean energy to meet peak demands, but it may be difficult to implement in a flexible, simple, and evolving way. It may not address the broader goal of ensuring renewable energy meets system reliability needs and may need to evolve as system needs change. Additionally, it does not address local distribution system needs.

- **Renewable Capacity Standard (RCS)** – like an RES, an RCS would require that a certain percentage of a utility's required capacity to meet reliability needs be sourced from renewable resources. It has some of the same challenges that face the clean peak target.

- **Incentives** – utilities, with Commission approval, could provide performance-based incentives for resources that provide both clean energy and meet peak and reliability needs. In defining such incentives, the Commission will have numerous considerations, including whether they apply only to new resources, or if existing resources that provide peak or reliability services should be eligible for such incentives.

- **Resource planning** – a stronger Integrated Resource Planning process, with a clear, enforceable action plan, could provide the Commission an opportunity to direct utilities to adopt renewable energy and DSM resources that also meet the system's peak and reliability needs. By working through the resource planning process, the Commission would have the flexibility to consider evolving system needs, emerging technologies, and different utilities' particular systems. Strengthening the Integrated Resource Planning process would also include a more detailed analysis of distribution system needs and the potential for using distributed energy resources to meet those needs as well as bulk power system needs.

We encourage the Commission to evaluate each of these policy options, particularly in the context of a rapidly-changing electric sector.

5. Energy Storage

This section addresses the Commission's questions about the benefits and applicability of storage, costs, and the appropriate level of storage targets.

Energy storage, specifically battery storage, has become a widely accepted source to serve peak load and a responsive, reliable, and cost-effective method of providing some ancillary services, and an economical way for customers and utilities to perform energy arbitrage. We support the use of energy storage for a variety of applications, such as hybridizing solar and wind for providing firm capacity to meet peak load, leveraging energy efficiency/DSM technologies (like connected water heaters), shifting energy delivery from periods of the day when there is ample electricity supply and energy prices are low to periods when prices are high (energy arbitrage), providing ancillary services, and backup energy for reliability, to name a few.

Several types of energy storage technologies are currently available. The most common type of battery storage, lithium ion batteries, have grown in scale significantly in recent years, moving from kWh pilots to MWh utility scale applications nationally and internationally. They are reliable, flexible, and cost-effective in a number of applications. Operationally, lithium ion battery storage is a very flexible resource, with fast and accurate response to peak load and fluctuation in frequency. In addition, other types of batteries are being developed and demonstrated for large-scale electricity storage. The PJM Interconnection has been meeting frequency response needs with large battery storage installations for several years. For detailed descriptions of hundreds of utility storage projects using different technology types, the Department of Energy has created a website, the United States Department of Energy (DOE) Global Energy Storage Database[25], for projects around the world. This database can be searched by country, technology, rated power, duration and other dimensions.

One of the main applications for energy storage is meeting peak demand, particularly using energy stored when it is cheap and plentiful (e.g., during daylight hours of solar production). Using energy storage to meet peak demand is already economical, with storage plus utility scale solar being contracted today at lower prices than new natural gas combustion turbines [add footnote]. We expect that a significant portion of peak demand requirements in Arizona could be accommodated during the next five to ten years by utility-scale and distributed solar installations plus 4-6 hours of battery storage. We believe all *__new__* peak demand requirements could be economically met by solar plus storage, as well as through energy efficiency/DSM measures.[26]

Two recent projects in Arizona illustrate that batteries paired with renewables can economically meet peak demands: APS recently signed a PPA with First Solar to develop a 50 MW solar project paired with a 135 MWh battery.[27] Similarly, in 2017, TEP signed a PPA for a 100 MW solar project paired with a 30 MW/120 MWh battery, for a total cost of less than 4.5 cents/kWh.[28] We believe that the responses to such RFPs indicate that a "tipping point" in the price of battery storage may have already been reached, and that battery storage will continue to be cheaper than new natural gas combustion turbines (peakers).

A target of 3,000 MW of 4-to-6-hour storage is not only attainable, it is realistic by 2030. In the Joint Stakeholders' comments filed in the IRP docket, the Alternative Portfolios included a total of 2,530 MW of storage by 2032 for APS and TEP (approximately 2,000 MW by 2030). We expect that, when the energy needs of SRP and other electricity providers are included, the 3,000 MW target is realistic. As peak demand increases for each utility, storage and renewables can be added, negating the need for new natural gas combustion turbines and increased

---

[25] DOE Global Energy Storage Database, https://www.energystorageexchange.org/projects

[26] In addition, energy efficiency/DSM can be implemented in parallel to reduce peak demand, thereby resulting in total lower *net* peak demand that solar plus storage would need to meet.

[27] https://www.aps.com/en/ourcompany/news/latestnews/Pages/aps-first-solar-partner-on-arizonas-largest-battery-storage-project.aspx

[28] https://www.utilitydive.com/news/updated-tucson-electric-signs-solar-storage-ppa-for-less-than-45kwh/443293/

reliance on fossil fuels. The timeframe for the addition of 3,000 MW of storage should be consistent with the need for new capacity to meet higher peak demand.

Utilities are at the beginning of the learning curve with storage. Utilities should be encouraged to investigate where and what type of storage is most cost effective and where it can provide the most benefits to the electric system. This may or may not be to address peak load conditions. Frequency regulation is an application that has had widespread acceptance by utilities in other parts of the country. Battery storage can address frequency regulation with faster response times than spinning turbines. Battery or other energy storage can also be used to move excess solar energy during spring and fall months from mid-day to evening hours. This function can also be a secondary application for storage designed primarily for peak load support.

In sum, we expect battery storage, both paired with renewables and integrated as stand-alone resources at high value locations on the grid, will continue to be cost effective, and that the *Energy Modernization Plan*'s target of 3,000 MW by 2030 is achievable. However, we expect that the appropriate level of utility and customer investment in energy storage will depend on individual utility circumstances – their peak demands, ramping needs, growth patterns, use of electric vehicles, and other grid issues. Accordingly, we encourage the Commission to direct utilities to conduct explicit storage planning, possibly as part of a more robust Integrated Resource Planning process.

6. Forest Health/Biomass-Related Energy

The health of Arizona's forests is crucially important. The impacts of drought, fire and insect predation on Arizona forests should be addressed. Fire mitigation efforts that thin overgrown forests will help mitigate fire danger, but also bring impacts to the forests that should not be ignored.

We are concerned with the environmental impact of removing vast quantities of biomass from Arizona forests and trucking it to power plants for burning. First, roads will need to be built in otherwise road-less areas to haul the biomass to a generation site, damaging the ecosystem. Roads fragment the land, open it up to vehicular traffic over the long term, impacting animals' movement, and generally degrading the forests. The actual hauling of the wood with large trucks is costly and has large environmental impacts from combustion byproducts and additional damage to forest ecosystems. Tree thinning with shredding in place can have a much smaller impact on the forests than building larger and more extensive roads to haul out the slash.

The recent APS report on biomass energy[29] provides a good analysis of the costs and some of the issues associated with using biomass from forest thinning for the generation of energy in steam turbines. APS estimates a PPA for existing 14 MW from Novo BioPower with an additional 30 MW of bioenergy (also a PPA) from a new generation facility would cost approximately $198/MWh. Given that new solar energy costs $30 - $40/MWh and solar plus storage prices are modestly higher, the price for new bioenergy would, comparatively, be very high. Increasing the size of the facility from 30 MW of bioenergy capacity to 60 MW of capacity

[29] APS Forest Bioenergy Report, Arizona Public Service, 2017, filed in Dockets No. E-01345A-16-0036 and E-01345A-16-0123.

would bring the price down slightly, to $178/MWh. APS estimates that adding these amounts would increase the average residential customer's bill by $1.54 and $2.57 per month, respectively. This is not insignificant, especially when compared to the cost savings that can be achieved for customers when energy efficiency/DSM or solar plus battery storage is utilized instead of natural gas combustion turbines. We expect that other technologies, including energy efficiency/DSM and renewables paired with battery storage, will be more cost effective than bioenergy projects, and with much less environmental impact.

Despite these cost estimates, other biomass projects may be viable and cost-effective, and minimize environmental impacts. We encourage the Commission not to create a biomass requirement at this time, but to allow biomass to compete with other resources in competitive bidding or procurement, and to evaluate biomass as part of the utilities' Integrated Resource Planning process.

7. Energy Efficiency and Demand-Side Management (DSM)

Electric energy efficiency/DSM is in the public interest for many reasons. Energy efficiency/DSM:

- Is a low-cost energy and capacity resource.
- Provides significant and cost-effective benefits for all electric customers, the electric system, the economy, and the environment.
- Saves consumers and businesses money through lower electric bills and the deferral of unnecessary infrastructure, resulting in lower total costs for customers.
- Reduces load (resulting in lower *net* load to serve) and diversifies energy resources.
- Reduces air pollution and the amount of water used for power generation. And,
- Mitigates electricity and fuel price increases and reduces customer vulnerability and exposure to price volatility.

The Commission's existing Energy Efficiency Standard, which requires 22% energy savings by 2020, is cost-effective and has driven significant savings and benefits for Arizona ratepayers:

- Every $1 invested has returned more than $2 in benefits.[30]
- Ratepayers have saved more than a billion dollars since 2008.[31]
- Arizona's nationally-recognized energy-saving programs[32] have served hundreds of thousands of Arizona residents and businesses.[33] And

[30] See the Annual Demand Side Management Reports of APS and TEP

[31] Ibid. at 23.

[32] Examples include: Wall Street Journal, "APS and Unisource AZ Utilities Get National Awards for Energy Efficiency," http://online.wsj.com/article/PR-CO-20130328-914083.html; Phoenix Business Journal, "APS, Meritage, Foundation for Senior Living tabbed for Energy Star awards," http://www.bizjournals.com/phoenix/news/2013/03/26/aps-meritagefoundation-for-senior.html; Greentech Media, "Multifamily Housing: A $3.4B US Energy Efficiency Opportunity," http://www.greentechmedia.com/articles/read/multifamily-housing-a-3.4b-u.s.-energy-efficiency-opportunity

[33] Arizona Public Service, "APS DSM Program Overview, "Presented at the 2013 ACEEE National Conference on Energy Efficiency as a Resource.

- Thousands of Arizonans have been to work upgrading buildings, improving manufacturing production lines, and installing new sensors and controls.[34]

Energy efficiency and DSM investments can be targeted to meet system needs by emphasizing DSM measures that provide cost-effective benefits to customers, reduce summer peak demands, and provide load reductions during ramping and other periods to assist with meeting system reliability needs at low costs. Energy efficiency is load-following, meaning that the largest savings and reductions in demand generally are at the times of highest end-use demand. Industry trends in building and process automation, combined with technology advances in software and controls, creates the opportunity for integrated energy efficiency and demand management to provide significant cost savings for customers while also enabling the management of customer loads to meet system needs (e.g., peak demand, ramping, or operational needs) at specific times. For these reasons, continued investment in energy efficiency/DSM post-2020 is critical to, "Complement the goal of achieving 80% clean energy resources by 2050, while reducing costs to ratepayers," as Commissioner Tobin noted in his proposal.

With the Commission's existing energy efficiency policy ending in 2020, the Commission should support the development and implementation of a "new" energy efficiency/DSM policy, either as: (1) an extension, expansion, and update of the existing Energy Efficiency Standard, or (2) a new requirement as an enforceable target (including interim targets for energy efficiency). Either option would be an enforceable requirement and would serve as a floor for utility energy savings acquisition.

For example, the Commission could: (1) adopt a new or extended EE Standard for at least 10 years (e.g., 20% cumulative energy savings achieved over the 2021-2030 period); (2) provide credit for DSM measure performance during specific times to meet peak demand, ramping, and operational needs through the clean peak standard; and (3) develop large scale DSM programs that make use of the capability offered by new technology in customer facilities (controls and software) combined with data from AMI and smart meters.

8. Electric Vehicles

This section addresses Commission questions on the potential benefits of electric vehicles, the role for utility investment in and Commission oversight of transportation electrification, actions that other states are taking on EVs, and recommendations on how the Commission and utilities should proceed.

Electric vehicles (EVs) can offer important benefits for Arizona: EVs can improve the utilization of the grid by battery charging when excess capacity is available or energy is cheap and plentiful, which can reduce overall consumer rates; Arizonans who drive EVs can save between $700 - $1,400 per year on fuel, redirecting that money into the Arizona economy[35]; and EVs can

[34] Energy Efficiency Jobs in America, E2 and E4TheFuture, December 9, 2016, https://www.e2.org/wp-content/uploads/2016/12/EnergyEfficiencyJobsInAmerica_FINAL.pdf

[35] Salisbury, M., 2013. "Air Quality and Economic Benefits of Electric Vehicles in Arizona," Southwest Energy Efficiency Project, available at

provide important air quality and public health benefits. For example, an EV driven in Maricopa County, when compared with a gasoline-fueled vehicle, reduces emissions of volatile organic compounds and carbon monoxide by 99%, sulfur dioxide by 93%, nitrogen oxide emissions by 76%, and particulate matter by 45 – 60% (for PM 10 and PM 2.5, respectively).[36] These effects – particularly the air quality and improved grid utilization – benefit all consumers, not just EV owners.

To realize these benefits, Arizona needs significantly higher rates of EV adoption. Because of the broad benefits of EVs to consumers, it is appropriate for the Commission to support utility actions and investments that accelerate EV adoption. Today, EVs represent a small portion of total sales, though falling prices of batteries, increased vehicle range, and increased consumer choice in EV models all suggest EV adoption rates will increase.

Utilities can help accelerate EV adoption by:

- Ensuring that EV charging infrastructure is readily available, particularly in underserved markets (this includes electric grid infrastructure upgrades and improvements on both sides of the meter to ensure that everything is "ready" for the installation of charging stations);
- Supporting electrification of public transit;
- Providing EV rates that support EV adoption and incentivize charging to maximize grid benefits; and
- Supporting adoption through marketing, communication, and education efforts to customers — to name a few.

Other states and utilities have begun developing programs to support EV adoption. Table 5 provides several examples.

Table 5. Selection of EV programs offered by utilities in other states.

Utility	Program/Plan Highlights
Eversource (Massachusetts)	• Plans to install make-ready infrastructure for 4,000 charging stations over the next five years, representing an investment of approximately $45 million • Installations include charging stations at workplaces, multi-unit dwellings, and other long dwell time locations • Ten percent (10%) of these charging stations will be installed in low-income communities
NV Energy (Nevada)	• Shared investment program to support charging at universities, casinos, resorts, shopping centers, recreation destinations and airports[37] • Partnership with the Nevada Energy Office to develop fast charging along highways

http://www.swenergy.org/data/sites/1/media/documents/publications/documents/AZ%20EV%20AirQuality.EconAnalysis.9.26.13%20.pdf

[36] Ibid.

[37] "NV Energy: Leading the Way on Electric Vehicles," Southwest Energy Efficiency Project, August 2014, http://mojo.swenergy.org/data/sites/1/media/documents/publications/documents/NV_Energy_Leading_the_Way_on_EVs_08-2014.pdf

California utilities	• The three largest IOUs have filed transportation electrification plans with the California Public Utilities Commission that include proposals for light and heavy-duty infrastructure investment, rate design for residential, commercial, and DC fast charging, together totaling approximately $1 billion in investment. • Previously, programs were approved in 2016 to allow Pacific Gas and Electric to invest in 7,500 Level 2 charging stations and 100 DC Fast Charging stations at a cost of $160 million (0.2 percent rate impact); for San Diego Gas and Electric to invest in 3,500 stations; and for Southern California Edison to invest in 1,000 stations.

The effect of EVs on utility infrastructure is still uncertain; however, it is important that utilities evaluate the demands and the potential benefits in a both a qualitative and quantitative manner. Various utility and academic studies[38] have evaluated key EV issues, including the number, type, and distribution of EV charging stations; charging energy demands and impact on peak demands; and the ability to shift charging to off-peak times to maximize customer benefits. We recommend the Commission direct utilities to develop similar studies, evaluating the following levels of EV penetration in their service territories:

- Moderate adoption level: 4% of all passenger vehicles (including fleet vehicles) in 2025 are battery electric (BEV) or plug in hybrid electric vehicles (PHEVs).[39]
- High adoption level: 8% of passenger vehicles are BEVs or PHEVs in 2025. This level of adoption is consistent with achieving a target of 1 million EVs in Arizona by 2030.[40]

Those studies should quantify:

- Total electric demand;
- The number, type, and cost of charging stations under a scenario where most charging takes place at home, overnight;
- The number, type, and cost of charging stations, under a scenario where higher levels of charging take place during the day in order to utilize low-cost solar PV;
- The appropriate mix of public and private charging stations;
- The most advantageous locations for charging and other infrastructure; and
- The role of utilities in scenarios where they own both public and private charging stations and where they do not, and where there is mixed ownership in the marketplace.

We believe this type of focused study can help identify the potential customer benefits of electric vehicles and inform the appropriate level of utility investment in EV charging infrastructure. The

[38] See, for example: Phoenix Business Journal, January 18, 2018. "SRP studying how electric vehicles impact the power grid," https://www.bizjournals.com/phoenix/news/2018/01/18/srp-studying-how-electric-vehiclesimpact-the.html; Southern California Edison, 2017. The Clean Power and Electrification Pathway, https://www.edison.com/content/dam/eix/documents/our-perspective/g17-pathway-to-2030-white-paper.pdf; U.S. Department of Energy, 2017. National Plug-In Electric Vehicle Infrastructure Analysis; Ceres and MJB&A, 2017. Accelerating Investment in Electric Vehicle Charging Infrastructure: Estimated Needs in Selected Utility Service Territories in Seven States.

[39] This level is consistent with recent national projections by Edison Electric Institute and Bloomberg New Energy Finance, but less than the estimated amount of EVs in the vehicle fleet in states that have adopted a ZEV sales requirement as part of a vehicle fuel efficiency standard.

[40] This is also roughly consistent with the most aggressive state goals, including California's EV targets.

plans should inform utilities' strategic investments in EV charging infrastructure and promoting EV sales. Furthermore, we recommend these plans be developed in a separate, dedicated proceeding focused on transportation electrification. The magnitude of the potential effect of – and investment in – electric vehicles merits its own proceeding and Commission attention, outside of an Integrated Resource Plan or energy efficiency/DSM process.

In sum, electric vehicles present an important opportunity for utilities, customers, and the Commission. We recommend the Commission move forward quickly by directing utilities to develop infrastructure plans that support electric vehicles as part of the *Energy Modernization Plan* proceeding, or in an independent proceeding (separate from the Integrated Resource Plan or energy efficiency/DSM process).

9. Integrated Resource and Transmission Planning

The following comments summarize our recommendations for improving the Integrated Resource Planning process.

The integrated resource planning (IRP) process reflects utility investment decisions worth billions of dollars, with attendant impacts on ratepayers. The ability for stakeholders to effectively engage in the process, therefore, is essential. We encourage the Commission to develop a more robust resource planning process that incorporates more stakeholder input. Stakeholders have demonstrated thoughtful review and comment on draft plans prepared by utilities, presenting information and perspective not provided by the regulated companies. This past IRP round stakeholders developed alternative resource scenarios that were more expansive, reasonable and economical than utilities plans. Specifically, we recommend the Commission require utilities to evaluate and present one or more alternative portfolios proposed by stakeholders in all future IRP proceedings.[41]

The Commission should also consider adding Distribution System and Storage Planning to the IRP process. Distribution System Planning is a concept under development by Commissions in Colorado and Nevada (sometimes called Distribution Resource Planning). This process would incorporate distribution grid load and hosting capacity analysis, along with forecasting of load growth and the growth of customer adoption of distributed generation and storage, to look at how Distributed Energy Resources (distributed generation, battery storage, EVs, DSM, including geo-targeted DSM) can be used to reduce the costs of distribution system expansion and modernization and improve the day-to-day operation of the distribution system. Utilities throughout the U.S. are looking at "non-wires" solutions to defer or avoid investments for distribution and transmission capacity expansion. In addition, advances in inverter technology can enable utilities to manage voltage and power quality at lower costs. A robust Distribution System Planning process, as part of the IRP, can help identify cost effective solutions that reduce capital expenses and save customers money.

We support the Commission's direction to hire an independent consultant to review, analyze and offer perspective to the Commission on filed utility plans, provided that the consultant is

[41] We recommend this in addition to the positive amendments adopted by the Commission during the March 13, 2018, Commission Open Meeting to improve the effectiveness of future IRP proceedings, which we appreciate.

financially independent of the utilities, i.e. not on contract or paid by them. We also recommend that the Commission host one or more workshops with the consultants to ensure that Stakeholder data, recommendations and perspectives are included in a final report to Commissioners for their consideration.

Additionally, we recommend that the Commission review and vote to adopt, modify, or reject (and not just "acknowledge" or "not acknowledge") a near-term action plan in each utility IRP proceeding as part of Commission review and action on each of the utility IRPs. The near-term action plans and Commission review and approval should focus on a six-year period of "near-term" decisions and actions that are needed to ensure system needs are met in a reliable and cost-efficient manner. Due to the pace of technology change, potential for non-fossil resources to play a more prominent role in the future in Arizona's electric system, and the long-term nature of investments, a change to an approval process for IRPs is warranted.

Finally, the Commission needs to stay up-to-date with development of regional transmission markets that will fundamentally change the way that the electric system is planned and operated for utilities that join these markets. Arizona utilities have already joined the Western Energy Imbalance Market and will have options to join Regional Transmission Organizations within the decade. It is crucial that future resource planning processes take into consideration the status of regional markets as participation in these markets can significantly improve reliability, decrease consumers costs and shape the resources needed to meet Arizona's electric needs.

10. Security and Reliability/Resiliency

The *Energy Modernization Plan* will increase the diversity of energy resources for all utilities, which, if implemented properly, will increase overall reliability. Future reliability is a concern for Arizona with reliance on too much generation from natural gas due to the lack of in-state storage facilities and need for expanded pipeline infrastructure. The *Energy Modernization Plan* reduces reliance on natural gas generation by utilizing more wind, solar, DSM, energy storage, and EVs. Natural gas resources are used more sparingly, which assures that if fuel supply interruptions occur, they may operate for a longer duration.

In addition to the broad benefits of the *Energy Modernization Plan*, overall grid reliability in Arizona can be improved through modernizing the distribution grid. Technology advances are revolutionizing the speed and accuracy of fault identification and correction. Many utilities have replaced older Distribution Management Systems (DMS) with newer Advanced Distribution Management Systems (ADMS). The new ADMS allow real time monitoring of multiple sensors around the grid, including AMI smart meters at customer locations. In the past, many outages were only detected by the utility when customers call about the outage. The utility would plot the extent of the outage based on where customers were calling from. Today, a utility with an ADMS with Fault Location, Isolation, and Service Restoration (FLISR) software can automatically locate areas with an outage, isolate the outage with distribution switch gear, and dispatch crews immediately for repair. Utilities now also have the ability to install automated switch gear in the distribution grid that will automatically reconfigure the grid to minimize the area of an outage. These modernization efforts can dramatically reduce outage duration and the number of outages customers experience in a year. The Commission should evaluate the status of grid modernization within each utility and encourage investment if a utility is lacking. This process should be part of the Distribution System Planning activities discussed above.

11. Conclusion

The Commission has the opportunity with the *Energy Modernization Plan* to assess the multitude of energy options and provide a framework for utilities to develop a set of resources that will result in a more reliable, affordable and cleaner electric system. We recommend that the Commission work to define the *Plan* with the intent to maximize the most cost-effective, clean resources to meet customer needs.

Thank you for the opportunity to submit these comments.

Western Resource Advocates (WRA)

The Arizona Utility Ratepayer Alliance (AURA)

Diné CARE

To Nizhoni Ani (TNA)

DinéHózhó

The Tucson 2030 District

The National Association of Energy Service Companies (NAESCO)

Western Grid Group

The Conservative Alliance for Solar Energy (CASE)

Efficiency First National

The Southwest Energy Efficiency Project (SWEEP)

Physicians for Social Responsibility - Arizona Chapter

Vote Solar

About the Joint Stakeholders

Founded in 1989, **Western Resource Advocates** is dedicated to protecting the West's land, air, and water to ensure that vibrant communities exist in balance with nature. WRA uses law, science, and economics to craft innovative solutions to the most pressing conservation issues in the region.

The **Arizona Utility Ratepayer Alliance (AURA)** was founded in 2015 to advise and represent utility ratepayers on vital issues affecting their pocketbook. AURA is a nonpolitical, non-partisan organization advocating on behalf of everyday Arizonans to ensure that utilities act responsibly with affordable rates, subject to transparent regulation, while providing sustainable utility services. Independent from the Governor's Office, Legislature, or any other government entity, AURA is unique in its commitment to all Arizona ratepayers, advocating effective and efficient utility oversight.

Diné CARE is an all-Navajo community conservation organization. Based within the Navajo homeland, Diné CARE has worked closely with Navajo communities affected by energy and environmental issues since the late 1980s, helping them demand environmental protection and sustainable development practices, bringing systemic changes in tribal politics and helping elevate the voice of these communities.

Founded in 2000, **Tó Nizhóni Ání** works to preserve and protect the environment, land, water, sky and people of the Navajo Nation and to advocate for the wise and responsible use of the natural resources of the Black Mesa region.

DinéHózhó is organized as a Low-Profit Limited Liability Company (L3C) incorporated on the Navajo Nation. Its mission is to integrate Navajo culture, sustainability, conservation, and local knowledge in an effort to transition the Navajo toward a place-based, sustainable economy that improves the Diné quality of life.

The **Tucson 2030 District** is a private-public-nonprofit collaborative working to create groundbreaking high-performance building districts in Tucson that aim to dramatically reduce energy and water consumption.

The **National Association of Energy Service Companies (NAESCO)** is the leading national trade association of the energy services industry. During the last thirty years, NAESCO member companies have delivered thousands of energy efficiency, renewable energy, demand response, distributed generation and combined heat and power projects across the United States and around the globe. Nationally, NAESCO member companies have delivered $50 billion in projects that have produced $55 billion in guaranteed and verified energy savings, which repay the cost of the projects and provide positive economic impacts to local communities.

The mission of **Western Grid Group** is to develop and work to implement policies to improve the efficiency of the existing grid, through technology and market changes, to provide near-term access for clean power; ensure transmission and system planning incorporates all cost-effective energy efficiency, dynamic load resources and distributed generation, and minimizes and mitigates electric sector environmental impacts; and expand the grid, to access and deliver renewable energy; minimize life-cycle greenhouse gas emissions; and enhance system reliability.

The **Conservative Alliance for Solar Energy (CASE)** is a coalition of solar energy advocates committed to educating Arizona policy makers on the value and benefit of residential solar production.

Efficiency First is America's national trade association for the building performance industry. It is a non-profit organization dedicated to transforming America's building performance industry into a strong workforce. It has a network of hundreds of member organizations that all have a shared passion: to grow the industry into a sustainable, profitable market sector, creating more local jobs, and delivering energy efficiencies that save homeowners money.

The **Southwest Energy Efficiency Project (SWEEP)** is a public-interest organization promoting greater energy efficiency in Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming. SWEEP collaborates with utilities, state and local governments, environmental groups, national laboratories, businesses, and other energy experts; and works to improve the energy efficiency of buildings, transportation, and the utility sectors.

Physicians for Social Responsibility, Arizona Chapter is based in Tucson, but serves members throughout the state. The Chapter is made up of physicians, other health professionals and members of the public who share the organization's mission and vision. It has worked consistently to encourage movement in Arizona communities toward clean, safe and renewable energies, reduction of carbon pollution, and to mitigate climate change.

Since 2002, **Vote Solar** has been working to make solar affordable and accessible to more Americans. It works at the state level all across the country to support the policies and programs needed to repower the grid with clean energy.

PROPOSED RULE

TITLE 17 PUBLIC UTILITIES AND UTILITY SERVICES
CHAPTER 9 ELECTRIC SERVICES
PART 571 CLEAN ENERGY STANDARD RULE FOR ELECTRIC UTILITIES

§17.9.571.1 ISSUING AGENCY: New Mexico Public Regulation Commission

§17.9.571.2 SCOPE: All electric utilities as defined herein are subject to §§17.9.571.1 through 14 NMAC.

§17.9.571.3 STATUTORY AUTHORITY: §§62-3-1, 62-6-4, 62-6-28, 62-8-2, 62-9-1, 62-9-3, 62-16-2, 62-16-4, 62-16-6, 62-17-2, 62-17-3 NMSA 1978.

§17.9.571.4 DURATION: Permanent.

§17.9.571.5 EFFECTIVE DATE: _______________, 2018.

§17.9.571.6 OBJECTIVE: The purpose of this rule is to set forth a clean energy standard for electric utilities that addresses these considerations:

(1) electric utilities today face costs and risks of state and federal regulation of pollutants that adversely impact human health and the environment. Electric utilities that manage that risk and reduce carbon-dioxide emissions in accordance with the requirements of this rule will be well positioned to minimize the future costs and risks of serving their customers;

(2) combustion methods for producing electricity typically emit more pollutants than other forms of electricity production and, therefore, reducing carbon-dioxide emissions is an appropriate means by which to reduce costs and risks associated with some forms of electricity production;

(3) electric utilities that reduce their carbon-dioxide footprint in accordance with this rule can bring significant economic benefits to New Mexico through, among other things, lower electricity rates and reduced risk to consumers and shareholders, as well as development of the clean energy resources that New Mexico has in abundance. Other benefits include fostering energy self-sufficiency, addressing climate change, providing economic growth, reducing health costs and improving the environment of New Mexico and beyond;

(5) having the requirements of this rule tied to the amount of electricity a utility serves to its New Mexico customers will assure genuine emission reductions and provide a strong incentive for energy conservation and efficiency; and

(6) the public interest will be served if New Mexico electric utilities provide their customers with increasingly clean energy over time.

§17.9.571.7 DEFINITIONS: Unless otherwise specified, as used in this rule:

A. "base period emissions" means the average annual metric tons of carbon-dioxide that the utility emitted into the atmosphere from its New Mexico dedicated generation during a consecutive three-calendar-year period of 2010 to 2012;

B. "clean energy credit," "credit" or "CEC" means an instrument, in a physical or electronic format approved by the commission that represents, for every gigawatt-hour produced by New Mexico dedicated generation in a year, each metric ton of carbon-dioxide emissions less than one thousand. For any electric generating facility that is awarded renewable energy certificates associated with its electricity production, emissions of less than one-thousand metric tons per gigawatt-hour will only be recognized in the base period emissions determination, and in the award of clean energy credits during a compliance period, if the renewable energy certificate (REC) associated with that production is retired by the utility. If the REC is not retired by the utility, the energy shall not receive any credits

C. "commission" means the New Mexico public regulation commission;

D. "dedicated generation" means electric energy production capacity that is assigned to the utility for New Mexico ratemaking purposes, and that is either owned by the utility or a corporate affiliate, or committed to the utility or a corporate affiliate pursuant to an agreement of five years or longer that specifies the particular generation resource from which the energy comes, less any such capacity sold by the utility pursuant to an agreement of five years or longer that specifies the particular generation resource from which the energy comes;

E. "emissions" means carbon-dioxide (CO_2) emitted into the atmosphere;

F. "emission reduction alternative" means a payment of $40 in calendar year 2019, escalating $1 each year thereafter, applied to commission-approved measures that reduce emissions outside of the electricity sector beyond those required by any law, rule or regulation;

G. "gigawatt-hour" means one thousand megawatt-hours or one million kilowatt-hours;

H. "New Mexico dedicated generation" means the energy produced from dedicated generation, adjusted as follows:

1) if that generation produces more energy in a year than the utility's New Mexico load, then New Mexico dedicated generation is the sum of all renewable energy from dedicated generation, plus the energy from the remaining dedicated generation proportionately reduced by multiplying the energy produced from each generator times the ratio of 1) the New Mexico load reduced by the energy produced by the renewable energy dedicated generation, to 2) the total megawatt-hours produced from the remaining (non-renewable) dedicated generation,

2) if that generation produces less energy in a year than the utility's New Mexico load, and a zero-emission generator experiences a forced outage of ninety days or longer, short-term (i.e. less than one year) power purchases up to the amount needed to replace the energy lost as a result of the outage, but not more than needed to meet its New Mexico load during the calendar year of the outage, shall be considered dedicated generation with an emission rate equal to the unspecified power rate;

I. "New Mexico load" means the megawatt-hours of electricity during a year that a utility sells to its New Mexico retail customers, plus line losses, minus load that has renewable resources dedicated to serve a particular customer, provided that the customer retains the REC, and does not use it for compliance with any law or regulation in any jurisdiction;

J. "plug-in electric vehicle" means a city and highway transportation vehicle that utilizes rechargeable batteries, or another energy storage device, that can be restored to full charge by connecting a plug to an external electric power source, but that only operates from an electric motor and not from an internal combustion engine;

K. "plug-in hybrid electric vehicle" means a city and highway transportation vehicle that utilizes rechargeable batteries, or another energy storage device, that can be restored to full charge by connecting a plug to an external electric power source, and that operates with both an electric motor and an internal combustion engine;

L. "undedicated power emission rate" means the metric tons of CO_2 per megawatt-hour identified in the Environmental Protection Agency's eGRID reports for the North American Electric Reliability Council (NERC) sub-region from which the power was procured. For calculating base period emissions, 2010 shall be used for 2010 and 2011, and the 2012 report shall be used for 2012. For compliance periods, the most recent eGRID reports shall be used.

1) In 2010 the eGRID AZNM sub-region rate was 0.54mT/MWh and the eGRID SPSO sub-region rate was 0.72mT/MWh;

2) In 2012 the eGRID AZNM sub-region rate was 0.52mT/MWh and the eGRID SPSO sub-region rate was 0.70mT/MWh; and

3) In 2014 the eGRID AZNM sub-region rate was 0.40mT/MWh and the eGRID SPSO sub-region rate was 0.67mT/MWh.

M. "utility" or "electric utility" means a public utility as defined in §62-3-3G NMSA, and any municipal electric utility or rural electric cooperative that submits to the commission by July 1, 2018 notice of its election to comply with the requirements of this rule.

§17.9.571.8 CLEAN ENERGY STANDARD:

A. A utility shall emit no more than its base period emissions in 2019, shall emit no more that ninety-six percent of its base period emissions in 2020, and shall continue to reduce its base period emissions by an additional four percent each year thereafter until January 1, 2040. For calendar year 2040 and thereafter emissions shall remain fixed at no greater than 80% below the annual base period emissions.

B. Each utility shall demonstrate compliance with the limitations of subsection A by the certified retirement of clean energy credits (CECs). A utility shall first present and retire CECs on or before July 1, 2022 for compliance in the 2019 through 2021 periods, and shall retire CECs every three years thereafter for compliance during that intervening three calendar year period. The commission will certify the retirement of CECs and otherwise assure compliance with this rule. If a utility retires an insufficient number of credits at the end of a compliance period it shall satisfy that deficiency by retiring 125 percent of the deficiency on or before July 1 of the year following the end of the next three-year compliance period. A utility may not exercise this deficiency provision in any two consecutive compliance periods.

C. To demonstrate compliance, a utility shall retire one CEC per year for each megawatt-hour of its New Mexico load in that year, less the number of metric tons of its base period emissions reduced by the percentage required in that year under subsection A. Specifically, at the end of each compliance period, the utility will retire the cumulative CECs required for each year of that period. In each year, the CEC retirement obligation equals the amount expressed by the following equation:

$$CEC_{retired} = L_y - E_b(1 - R_y)$$

y = year (2019, 2020...)
L_y = utility New Mexico load (MWh) plus line losses in *y*, *multiplied by 1.0 metric ton per MWh*
E_b = base period emissions
R_y = the reduction required in *y* (e.g. 0.00 in 2019, 0.04 in 2020, 0.08 in 2021...)

§17.9.571.9 CLEAN ENERGY CREDITS:

A. The commission will provide a utility one CEC each calendar year commencing in 2019 for each metric ton less than one thousand metric tons that it emits from its New Mexico dedicated generation, for every gigawatt-hour produced by that generation in that year. The commission will provide additional credits to a utility each year equal to the number of its emission reduction alternatives. The Commission will make this award by June 1 of the following year.

B. The commission will provide additional credits to a utility each year equal to three times the number of plug-in electric vehicles registered within the utility's New Mexico service territory multiplied by the undedicated power emission rate, plus one-and-on-half times the number of plug-in hybrid electric vehicles registered within the utility's New Mexico service territory multiplied by the undedicated power emission rate. The commission will make this award by June 1 of the following year. If New Mexico or the federal government adopts a regulation requiring CO_2 emission reductions from the transportation sector, the provision to provide CECs for plug-in electric vehicles and plug-in hybrid electric vehicles under the Clean Energy Standard may be revised by the Commission.

C. CECs may be sold, traded or otherwise transferred to any person, do not expire, and may be used at any time unless and until they are retired for compliance with this rule or another rule requiring carbon-dioxide reductions in another jurisdiction. Upon application by a utility, the commission may allow credits, allowances or other instruments from another jurisdiction that has a program to require comparable and systematic reduction of carbon-dioxide emissions over time, and that accepts CECs into its program, to be used for compliance in New Mexico.

§17.9.571.10 COMPLIANCE PROCEDURES:

A. On or before July 1, 2018, each utility shall file with the Commission a verified statement of its base period emissions. That statement shall include work-papers, supporting evidence, and documentation. The statement shall also either include New Mexico Environment Department verification that the CO_2 emissions identified by the utility are correct and consistent with those reported to the Environmental Protection Agency's Greenhouse Gas Reporting program, per CFR Part 98, or an explanation of why that certification could not be obtained. This filing shall be served on all parties to the utility's last New Mexico general rate-case, and notice of the filing shall be published in a newspaper or newspapers of general circulation in the utility's service area. If no protest to the statement is filed with the Commission within thirty (30) days of notice of the statement, it shall be deemed approved. If a protest is filed, the Commission will establish a procedure to determine by December 1, 2018 the appropriate base period emissions for the utility. Once established, the determination of base period emissions shall not be changed.

B. On or before July 1st of each calendar year commencing in 2020, each utility shall file with the Commission a verified statement of its entitlement to CECs for the prior calendar year, along with work-papers and other documentation supporting that statement. The statement shall also either include New Mexico Environment Department verification that the CO_2 emissions reported by the utility are correct and consistent with those reported to the Environmental Protection Agency's Greenhouse Gas Reporting program, per CFR Part 98, or an explanation of why that certification could not be obtained. This filing shall be served on all parties to the utility's last New Mexico general rate-case, and notice of the filing shall be published in a newspaper or newspapers of general circulation in the utility's service area. The utility may develop an Excel-based credit tracking and information system to assist in fulfilling this requirement. This filing shall include:

1) information to establish the utility's entitlement to CECs based on the production and emissions from the utility's New Mexico dedicated generation;
2) the number of plug-in, and plug-in hybrid, electric vehicles registered in the utility's service territory, and an explanation of how that amount was determined
3) documentation necessary to establish the number of its emission reduction alternatives;
4) a proposed format for the issuance of credits; and
5) an accounting and reconciliation of all credits that the utility has been awarded, has transferred, has banked and has retired for compliance.

If no protest to the statement is filed with the Commission within thirty (30) days of notice of the filing, the Commission may immediately award the requested number of credits in the format proposed by the utility or another format determined by the Commission. If a protest is filed, or if the Commission determines that further inquiry is appropriate, it will establish a procedure to determine and award by October 1 of that same year the correct number of CECs.

C. On or before July 1, 2022 for compliance in the 2019 through 2021 periods, and every three years thereafter for compliance during that next three year period, the utility shall certify to the Commission that it has retired the requisite number of CECs. This certification shall include verified information and documentation necessary for the Commission to determine that the required CECs have been retired and that the renewable energy certificates associated with reduced emissions from the dedicated generation of renewable energy resources have also been, or will be, retired by the utility.

§17.9.571.11 CLEAN ENERGY STANDARD ADVISORY COMMITTEE:

An advisory committee of no more than nine (9) members is established, to be chaired by a designee of the Commission, and to include a representative from each investor-owned utility to which this rule applies and, to the extent available to participate, a representative of rural electric cooperative utilities, municipal electric utilities, consumers, environmental advocates and the New Mexico Environmental Department. The Advisory Committee will provide guidance for the implementation of the rule and will consider at least the following issues during its pendency:

a) potential refinements or improvements to the rule;
b) outreach opportunities to share experience with the rule with policymakers and others;
c) refinements to the CEC amounts awarded for PEVs and PHEVs as their use expands and vehicle and generation technology advances;
d) exchangeability of CECs with allowances, credits or other similar instruments from other programs; and
e) capability of the rule to satisfy and comply with existing or future requirements.

The Advisory Committee shall report to the Commission no less frequently than every three years, and shall issue a final report and disband on January 1, 2030.

§17.9.571.12 OTHER LAWS AND REGULATIONS: This rule does not diminish or otherwise affect a public utility's obligation to comply with any other law or regulation, unless that law or regulation so provides.

§17.9.571.13 VARIANCES: Written applications for a variance from this rule shall:

A. state the reason(s) for the variance request;
B. identify each section of this rule for which a variance is requested;
C. describe the effect the variance will have on compliance with this rule;
D. describe how the variance will not compromise, or will further, the rule's purposes; and
E. describe why the variance would be a reasonable alternative to the rule's requirements.

II

112TH CONGRESS
2D SESSION

S. 2146

To amend the Public Utility Regulatory Policies Act of 1978 to create a market-oriented standard for clean electric energy generation, and for other purposes.

IN THE SENATE OF THE UNITED STATES

MARCH 1, 2012

Mr. BINGAMAN (for himself, Mr. WYDEN, Mr. SANDERS, Mr. UDALL of Colorado, Mr. FRANKEN, Mr. COONS, Mr. KERRY, Mr. WHITEHOUSE, and Mr. UDALL of New Mexico) introduced the following bill; which was read twice and referred to the Committee on Energy and Natural Resources

---

A BILL

To amend the Public Utility Regulatory Policies Act of 1978 to create a market-oriented standard for clean electric energy generation, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. SHORT TITLE.

This Act may be cited as the "Clean Energy Standard Act of 2012".

SEC. 2. FEDERAL CLEAN ENERGY STANDARD.

Title VI of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2601 et seq.) is amended by adding at the end the following:

"SEC. 610. FEDERAL CLEAN ENERGY STANDARD.

"(a) PURPOSE.—The purpose of this section is to create a market-oriented standard for electric energy generation that stimulates clean energy innovation and promotes a diverse set of low- and zero-carbon generation solutions in the United States at the lowest incremental cost to electric consumers.

"(b) DEFINITIONS.—In this section:

"(1) CLEAN ENERGY.—The term 'clean energy' means electric energy that is generated—

"(A) at a facility placed in service after December 31, 1991, using—

"(i) renewable energy;

"(ii) qualified renewable biomass;

"(iii) natural gas;

"(iv) hydropower;

"(v) nuclear power; or

"(vi) qualified waste-to-energy;

"(B) at a facility placed in service after the date of enactment of this section, using—

"(i) qualified combined heat and power; or "(ii) a source of energy, other than biomass, with lower annual carbon intensity than 0.82 metric tons of carbon dioxide equivalent per megawatt-hour;

"(C) as a result of qualified efficiency improvements or capacity additions; or

"(D) at a facility that captures carbon dioxide and prevents the release of the carbon dioxide into the atmosphere.

"(2) NATURAL GAS.—

"(A) INCLUSION.—The term 'natural gas' includes coal mine methane.

"(B) EXCLUSIONS.—The term 'natural gas' excludes landfill methane and biogas.

"(3) QUALIFIED COMBINED HEAT AND POWER.—

"(A) IN GENERAL.—The term 'qualified combined heat and power' means a system that—

"(i) uses the same energy source for the simultaneous or sequential generation of electrical energy and thermal energy;

"(ii) produces at least—

"(I) 20 percent of the useful energy of the system in the form of electricity; and

"(II) 20 percent of the useful energy in the form of useful thermal energy;

"(iii) to the extent the system uses biomass, uses only qualified renewable biomass; and

"(iv) operates with an energy efficiency percentage that is greater than 50 percent.

"(B) DETERMINATION OF ENERGY EFFICIENCY.—For purposes of subparagraph (A), the energy efficiency percentage of a combined heat and power system shall be determined in accordance with section 48(c)(3)(C)(i) of the Internal Revenue Code of 1986.

"(4) QUALIFIED EFFICIENCY IMPROVEMENTS OR CAPACITY ADDITIONS.—

"(A) IN GENERAL.—Subject to subparagraphs (B) and (C), the term 'qualified efficiency improvements or capacity additions' means efficiency improvements or capacity additions made after December 31, 1991, to—

"(i) a nuclear facility placed in service on or before December 31, 1991; or

"(ii) a hydropower facility placed in service on or before December 31, 1991.

"(B) EXCLUSION.—The term 'qualified efficiency improvements or capacity additions' does not include additional electric energy generated as a result of operational changes not directly associated with efficiency improvements or capacity additions.

"(C) MEASUREMENT AND CERTIFICATION.—In the case of hydropower, efficiency improvements and capacity additions under this paragraph shall be—

"(i) measured on the basis of the same water flow information that is used to determine the historic average annual generation for the applicable hydroelectric facility; and

"(ii) certified by the Secretary or the Commission.

"(5) QUALIFIED RENEWABLE BIOMASS.—The term 'qualified renewable biomass' means renewable biomass produced and harvested through land management practices that maintain or restore the com-position, structure, and processes of ecosystems, including the diversity of plant and animal communities, water quality, and the productive capacity of soil and the ecological systems.

"(6) QUALIFIED WASTE-TO-ENERGY.—The term 'qualified waste-to-energy' means energy produced—

"(A) from the combustion of—

"(i) post-recycled municipal solid waste;

"(ii) gas produced from the gasification or pyrolization of post-recycled municipal solid waste;

"(iii) biogas;

"(iv) landfill methane;

"(v) animal waste or animal byproducts; or

"(vi) wood, paper products that are not commonly recyclable, and vegetation (including trees and trimmings, yard waste, pallets, railroad ties, crates, and solid-wood manufacturing and construction debris), if diverted from or separated from other waste out of a municipal waste stream; and

"(B) at a facility that the Commission has certified, on an annual basis, is in compliance with all applicable Federal and State environmental permits, including—

"(i) in the case of a facility that commences operation before the date of enactment of this section, compliance with emission standards under sections 112 and 129 of the Clean Air Act (42 U.S.C. 7412, 7429) that apply as of the date of enactment of this section to new facilities within the applicable source category; and

"(ii) in the case of a facility that produces electric energy from the combustion, pyrolization, or gasification of municipal solid waste, certification that each local government unit from which the waste originates operates, participates in the operation of, contracts for, or otherwise provides for recycling services for residents of the local government unit.

"(7) RENEWABLE ENERGY.—The term 'renewable energy' means solar, wind, ocean, current, wave, tidal, or geothermal energy.

"(c) CLEAN ENERGY REQUIREMENT.—

"(1) IN GENERAL.—Effective beginning in calendar year 2015, each electric utility that sells electric energy to electric consumers in a State shall obtain a percentage of the electric energy the electric utility sells to electric consumers during a calendar year from clean energy.

"(2) PERCENTAGE REQUIRED.—The percentage of electric energy sold during a calendar year that is required to be clean energy under paragraph (1) shall be determined in accordance with the following table:

"Calendar year	Minimum annual percentage
2015	24
2016	27
2017	30
2018	33
2019	36
2020	39
2021	42
2022	45
2023	48
2024	51
2025	54
2026	57
2027	60
2028	63
2029	66
2030	69
2031	72
2032	75
2033	78
2034	81
2035	84.

"(3) DEDUCTION FOR ELECTRIC ENERGY GENERATED FROM HYDROPOWER OR NUCLEAR

POWER.—An electric utility that sells electric energy to electric consumers from a facility placed in service in the United States on or before December 31, 1991, using hydropower or nuclear power may deduct the quantity of the electric energy from the quantity to which the percentage in paragraph (2) applies.

"(d) MEANS OF COMPLIANCE.—An electric utility shall meet the requirements of subsection (c) by—

"(1) submitting to the Secretary clean energy credits issued under subsection (e);

"(2) making alternative compliance payments of 3 cents per kilowatt hour in accordance with subsection (i); or

"(3) taking a combination of actions described in paragraphs (1) and (2).

"(e) FEDERAL CLEAN ENERGY TRADING PROGRAM.—

"(1) ESTABLISHMENT.—Not later than 180 days after the date of enactment of this section, the Secretary shall establish a Federal clean energy credit trading program under which electric utilities may submit to the Secretary clean energy credits to certify compliance by the electric utilities with subsection (c).

"(2) CLEAN ENERGY CREDITS.—Except as provided in paragraph (3)(B), the Secretary shall issue to each generator of electric energy a quantity of clean energy credits determined in accordance with subsections (f) and (g).

"(3) ADMINISTRATION.—In carrying out the program under this subsection, the Secretary shall ensure that—

"(A) a clean energy credit shall be used only once for purposes of compliance with this section; and

"(B) a clean energy credit issued for clean energy generated and sold for resale under a contract in effect on the date of enactment of this section shall be issued to the purchasing electric utility, unless otherwise provided by the contract.

"(4) DELEGATION OF MARKET FUNCTION.—

"(A) IN GENERAL.—In carrying out the program under this subsection, the Secretary may delegate—

"(i) to 1 or more appropriate market-making entities, the administration of a national clean energy credit market for purposes of establishing a transparent national market for the sale or trade of clean energy credits; and

"(ii) to appropriate entities, the tracking of dispatch of clean generation.

"(B) ADMINISTRATION.—In making a delegation under subparagraph (A)(ii), the Secretary shall ensure that the tracking and reporting of information concerning the dispatch of clean generation is transparent, verifiable, and independent of any generation or load interests subject to an obligation under this section.

"(5) BANKING OF CLEAN ENERGY CREDITS.—Clean energy credits to be used for compliance purposes under subsection (c) shall be valid for the year in which the clean energy credits are issued or in any subsequent calendar year.

"(f) DETERMINATION OF QUANTITY OF CREDIT.—

"(1) IN GENERAL.—Except as otherwise provided in this subsection, the quantity of clean energy credits issued to each electric utility generating electric energy in the United States from clean energy shall be equal to the product of—

"(A) for each generator owned by a utility, the number of megawatt-hours of electric energy sold from that generator by the utility; and

"(B) the difference between—

"(i) 1.0; and

"(ii) the quotient obtained by dividing—

"(I) the annual carbon intensity of the generator, as determined in accordance with subsection (g), expressed in metric tons per megawatt-hour; by

"(II) 0.82.

"(2) NEGATIVE CREDITS.—Notwithstanding any other provision of this subsection, the Secretary shall not issue a negative quantity of clean energy credits to any generator.

"(3) QUALIFIED COMBINED HEAT AND POWER.—

"(A) IN GENERAL.—The quantity of clean energy credits issued to an owner of a qualified combined heat and power system in the United States shall be equal to the difference between—

"(i) the product obtained by multiplying—

"(I) the number of megawatt-hours of electric energy generated by the system; and

"(II) the difference between—

"(aa) 1.0; and

"(bb) the quotient obtained by dividing—

"(AA) the annual carbon intensity of the generator, as determined in accordance with subsection (g), expressed in metric tons per megawatt-hour; by

"(BB) 0.82; and

"(ii) the product obtained by multiplying—

"(I) the number of megawatt-hours of electric energy generated by the system that are consumed onsite by the facility; and

"(II) the annual target for electric energy sold during a calendar year that is required to be clean energy under subsection (c)(2).

"(B) ADDITIONAL CREDITS.—In addition to credits issued under subparagraph (A), the Secretary shall award clean energy credits to an owner of a qualified heat and power system in the United States for greenhouse gas emissions avoided as a result of the use of a qualified combined heat and power system, rather than a separate thermal source, to meet onsite thermal needs.

"(4) QUALIFIED WASTE-TO-ENERGY.—The quantity of clean energy credits issued to an electric utility generating electric energy in the United States from a qualified waste-to-energy facility shall be equal to the product obtained by multiplying—

"(A) the number of megawatt-hours of electric energy generated by the facility and sold by the utility; and

"(B) 1.0.

"(g) DETERMINATION OF ANNUAL CARBON INTENSITY OF GENERATING FACILITIES.—

"(1) IN GENERAL.—For purposes of determining the quantity of credits under subsection (f), except as provided in paragraph (2), the Secretary shall determine the annual carbon intensity of each generator by dividing—

"(A) the net annual carbon dioxide equivalent emissions of the generator; by

"(B) the annual quantity of electricity generated by the generator.

"(2) BIOMASS.—The Secretary shall—

"(A) not later than 180 days after the date of enactment of this section, issue interim regulations for determining the carbon intensity based on an initial consideration of the issues to be reported on under subparagraph (B);

"(B) not later than 180 days after the date of enactment of this section, enter into an agreement with the National Academy of Sciences under which the Academy shall—

"(i) evaluate models and methodologies for quantifying net changes in greenhouse gas emissions associated with generating electric energy from each significant source of qualified renewable biomass, including evaluation of additional sequestration or emissions associated with changes in land use by the production of the biomass; and "(ii) not later than 1 year after the date of enactment of this section, publish a report that includes—

"(I) a description of the evaluation required by clause (i); and

"(II) recommendations for determining the carbon intensity of electric energy generated from qualified renewable biomass under this section; and

"(C) not later than 180 days after the publication of the report under subparagraph (B)(ii), issue regulations for determining the carbon intensity of electric energy generated from qualified renewable biomass that take into account the report.

"(3) CONSULTATION.—The Secretary shall consult with—

"(A) the Administrator of the Environmental Protection Agency in determining the annual carbon intensity of generating facilities under paragraph (1); and

"(B) the Administrator of the Environmental Protection Agency, the Secretary of the Interior, and the Secretary of Agriculture in issuing regulations for determining the carbon intensity of electric energy generated by biomass under paragraph (2)(C).

"(h) CIVIL PENALTIES.—

"(1) IN GENERAL.—Subject to paragraph (2), an electric utility that fails to meet the requirements of this section shall be subject to a civil penalty in an amount equal to the product obtained by multiplying—

"(A) the number of kilowatt-hours of electric energy sold by the utility to electric consumers in violation of subsection (c); and

"(B) 200 percent of the value of the alternative compliance payment, as adjusted under subsection (m).

"(2) WAIVERS AND MITIGATION.—

"(A) FORCE MAJEURE.—The Secretary may mitigate or waive a civil penalty under this subsection if the electric utility was unable to comply with an applicable requirement of this section for reasons outside of the reasonable control of the utility.

"(B) REDUCTION FOR STATE PENALTIES.—The Secretary shall reduce the amount of a penalty determined under paragraph (1) by the amount paid by the electric utility to a State for failure to comply with the requirement of a State renewable energy program, if the State requirement is more stringent than the applicable requirement of this section.

"(3) PROCEDURE FOR ASSESSING PENALTY.—The Secretary shall assess a civil penalty under this subsection in accordance with section 333(d) of the Energy Policy and Conservation Act (42 U.S.C. 6303(d)).

"(i) ALTERNATIVE COMPLIANCE PAYMENTS.—An electric utility may satisfy the requirements of subsection (c), in whole or in part, by submitting in lieu of a clean energy credit issued under this section a payment equal to the amount required under subsection (d)(2), in accordance with such regulations as the Secretary may promulgate.

"(j) STATE ENERGY EFFICIENCY FUNDING PROGRAM.—

"(1) ESTABLISHMENT.—Not later than December 31, 2015, the Secretary shall establish a State energy efficiency funding program.

"(2) FUNDING.—All funds collected by the Secretary as alternative compliance payments under subsection (i), or as civil penalties under subsection (h), shall be used solely to carry out the program under this subsection.

"(3) DISTRIBUTION TO STATES.—

"(A) IN GENERAL.—An amount equal to 75 percent of the funds described in paragraph (2) shall be used by the Secretary, without further appropriation or fiscal year limitation, to provide funds to States for the implementation of State energy efficiency plans under section 362 of the Energy Policy and Conservation Act (42 U.S.C. 6322), in accordance with the proportion of those amounts collected by the Secretary from each State.

"(B) ACTION BY STATES.—A State that receives funds under this paragraph shall maintain such records and evidence of compliance as the Secretary may require.

"(4) GUIDELINES AND CRITERIA.—The Secretary may issue such additional guidelines and criteria for the program under this subsection as the Secretary determines to be appropriate.

"(k) EXEMPTIONS.—

"(1) IN GENERAL.—This section shall not apply during any calendar year to an electric utility that sold less than the applicable quantity described in paragraph (2) of megawatt-hours of electric energy to electric consumers during the preceding calendar year.

"(2) APPLICABLE QUANTITY.—For purposes of paragraph (1), the applicable quantity is—

"(A) in the case of calendar year 2015, 2,000,000;

"(B) in the case of calendar year 2016, 1,900,000;

"(C) in the case of calendar year 2017, 1,800,000;

"(D) in the case of calendar year 2018, 1,700,000;

"(E) in the case of calendar year 2019, 1,600,000;

"(F) in the case of calendar year 2020, 1,500,000;

"(G) in the case of calendar year 2021, 1,400,000;

"(H) in the case of calendar year 2022, 1,300,000;

"(I) in the case of calendar year 2023, 1,200,000;

"(J) in the case of calendar year 2024, 1,100,000; and

"(K) in the case of calendar year 2025 and each calendar year thereafter, 1,000,000.

"(3) CALCULATION OF ELECTRIC ENERGY SOLD.—

"(A) DEFINITIONS.—In this subsection, the terms 'affiliate' and 'associate company' have the meanings given the terms in section 1262 of the Energy Policy Act of 2005 (42 U.S.C. 16451).

"(B) INCLUSION.—For purposes of calculating the quantity of electric energy sold by an electric utility under this subsection, the quantity of electric energy sold by an affiliate of the electric utility or an associate company shall be treated as sold by the electric utility.

"(l) STATE PROGRAMS.—

"(1) SAVINGS PROVISION.—

"(A) IN GENERAL.—Subject to paragraph (2), nothing in this section affects the authority of a State or a political subdivision of a State to adopt or enforce any law or regulation relating to—

"(i) clean or renewable energy; or

"(ii) the regulation of an electric utility.

"(B) FEDERAL LAW.—No law or regulation of a State or a political subdivision of a State may relieve an electric utility from compliance with an applicable requirement of this section.

"(2) COORDINATION.—The Secretary, in consultation with States that have clean and renewable energy programs in effect, shall facilitate, to the maximum extent practicable, coordination between the Federal clean energy program under this section and the relevant State clean and renewable energy programs.

"(m) ADJUSTMENT OF ALTERNATIVE COMPLIANCE PAYMENT.—Not later than December 31, 2016, and annually thereafter, the Secretary shall—

"(1) increase by 5 percent the rate of the alternative compliance payment under subsection (d)(2); and

"(2) additionally adjust that rate for inflation, as the Secretary determines to be necessary.

"(n) REPORT ON CLEAN ENERGY RESOURCES THAT DO NOT GENERATE ELECTRIC ENERGY.—

"(1) IN GENERAL.—Not later than 3 years after the date of enactment of this section, the Secretary shall submit to Congress a report examining mechanisms to supplement the standard under this section by addressing clean energy resources that do not generate electric energy but that may substantially reduce electric energy loads, including energy efficiency, biomass converted to thermal energy, geothermal energy collected using heat pumps, thermal energy delivered through district heating systems, and waste heat used as industrial process heat.

"(2) POTENTIAL INTEGRATION.—The report under paragraph (1) shall examine the benefits and challenges of integrating the additional clean energy resources into the standard established by this section, including—

"(A) the extent to which such an integration would achieve the purposes of this section;

"(B) the manner in which a baseline describing the use of the resources could be developed that would ensure that only incremental action that increased the use of the resources received credit; and

"(C) the challenges of pricing the resources in a comparable manner between organized markets and vertically integrated markets, including options for the pricing.

"(3) COMPLEMENTARY POLICIES.—The report under paragraph (1) shall examine the benefits and challenges of using complementary policies or standards, other than the standard established under this section, to provide effective incentives for using the additional clean energy resources.

"(4) LEGISLATIVE RECOMMENDATIONS.—As part of the report under paragraph (1), the Secretary may provide legislative recommendations for changes to the standard established under this section or new complementary policies that would provide effective incentives for using the additional clean energy resources.

"(o) EXCLUSIONS.—This section does not apply to an electric utility located in the State of Alaska or Hawaii.

"(p) REGULATIONS.—Not later than 1 year after the date of enactment of this section, the Secretary shall promulgate regulations to implement this section.

"SEC. 611. REPORT ON NATURAL GAS CONSERVATION.

"Not later than 2 years after the date of enactment of this section, the Secretary shall submit to Congress a report that—

"(1) quantifies the losses of natural gas during the production and transportation of the natural gas; and

"(2) makes recommendations, as appropriate, for programs and policies to promote conservation of natural gas for beneficial use.".

○

f a c t   s h e e t

Electricity Sector Regulations

310 CMR 7.75: Clean Energy Standard
310 CMR 7.74: Reducing CO_2 Emissions from Electricity Generating Facilities

Overview

On August 11, 2017, the Massachusetts Executive Office of Environmental Affairs and the Massachusetts Department of Environmental Protection published two regulations to reduce CO_2 emissions from power plants in Massachusetts. 310 CMR: 7.75: *Clean Energy Standard* (CES) requires utilities and competitive suppliers of electricity to procure increasing amounts of clean energy in a similar manner to the Massachusetts Renewable Portfolio Standard (RPS). 310 CMR 7.74: *Reducing CO_2 Emissions from Electricity Generating Facilities* sets annually-declining emission limits for 21 in-state fossil fuel-powered power plants to ensure that emissions reductions associated with clean energy programs occur in Massachusetts.

Requirements

310 CMR 7.75:

- Sets a minimum percentage of electricity sales that utilities and competitive suppliers must procure from clean energy sources. Begins at 16% in 2018 and increases 2% annually to 80% in 2050.
  - RPS Class I compliance counts toward the CES (13% in 2018, increasing 1% per year to 45% in 2050).
- Allows for compliance using clean energy credits (CECs) or alternative compliance payments (ACPs).
- Requires eligible clean energy generators to be RPS-eligible or:
  - Demonstrate net lifecycle GHG emissions of at least 50% below those from the most efficient natural gas generator (e.g., hydro, nuclear, etc.);
  - Be located in the ISO-NE control area, or be located in an adjacent control area and utilize new transmission capacity;
  - Have commenced commercial operation after December 31, 2010.
- Energy procured pursuant to the 2016 Energy Diversity Act also counts toward compliance.
- Includes limited grandfathering of existing contracts between competitive suppliers and customers.
- Allows banking of clean energy credits (CECs) for use after 2020.
- Requires MassDEP to review options in 2017 for addressing existing (pre-2010) resources and municipal utilities, and complete a program review by December 31, 2021.

310 CMR 7.74:

- Establishes an allowance trading program for CO_2 emissions from electricity generation.
- Sets a sector-wide, annually declining limit on aggregate CO_2 emissions from 21 large fossil fuel-fired power plants in Massachusetts, from 8.96 million metric tons of CO_2 in 2018 down to 1.8 million metric tons in 2050.
- Includes allowance auctions beginning in 2019 (with direct allocations for 2018).
- Allows flexibility in the form of limited allowance banking and a "deferred compliance" option to address electricity grid reliability.

Massachusetts Department of Environmental Protection
One Winter Street
Boston, MA 02108-4746

Commonwealth of Massachusetts

Executive Office of Energy & Environmental Affairs

Department of Environmental Protection

August 2017.

This information is available in alternate format by calling our ADA Coordinator at (617) 574-6872.

- Requires MassDEP to complete a program review every ten years, beginning in 2021.

Changes to the Proposal

In response to public comment on the proposed regulations, the final regulations include the following changes.

310 CMR 7.75:

- The final CES does not include requirements for municipal utilities beyond already-required emissions reporting and the study referenced above. In the proposed rule, they were required to comply beginning in 2021.
- Limited grandfathering of existing contracts between competitive suppliers and customers has been added to accommodate electricity sold under existing contracts in 2018 and 2019.
- For years 2018 – 2020, the ACP rate is being increased to 75% of RPS amount to reflect the importance of achieving reductions by 2020. Beginning in 2021, the ACP rate will be 50% of the RPS amount, as proposed.
- The use of banked CECs is not allowed until 2021.

310 CMR 7.74:

- The final regulation's allowance trading program and the design of an auction system for 2019 replace the system of over-compliance credits contained in the proposal.
- The final regulation includes an "emergency deferred compliance" option in order to ensure grid reliability is not affected by the regulation.
- Banking of allowances is limited, to ensure emissions reductions annually.

Bill Impacts Study

Before finalizing the regulations, MassDEP hired expert consultants to study potential impacts on emissions and electricity prices. The study predicted that:

- Impacts on customer electricity bills are unlikely to exceed 1% to 2%.
- Allowance prices are likely to be low.
- The combined effect of the two regulations is to reduce emissions in Massachusetts and the region.

Additional Information

For more information about both regulations, see the MassDEP Clean Energy Standard web page: http://www.mass.gov/eea/agencies/massdep/climate-energy/climate/ghg/ces.html

Questions may be directed to:
william.space@state.ma.us, jordan.garfinkle@state.ma.us, or climate.strategies@state.ma.us

Massachusetts Department of
Environmental Protection
One Winter Street
Boston, MA 02108-4746

Commonwealth of
Massachusetts

Executive Office of
Energy & Environmental Affairs

Department of
Environmental Protection

This information is available in alternate format by calling our ADA Coordinator at (617) 574-6872.

APPENDIX C

INTERIOR CO_2 REDUCTION COMMITMENT
AND
INTERIOR CLEAN ENERGY DEVELOPMENT COMMITMENT

I. **Interior** makes the following two commitments to further a low carbon and clean energy future:

A. reducing or offsetting CO_2 emissions associated with electricity serving the **CAP** pumping load **("Interior's CO_2 Reduction Commitment")**; and

B. facilitating **Clean Energy** development **("Interior's Clean Energy Development Commitment")**.

II. **Interior's CO_2 Reduction Commitment**

A. **Interior** will not exceed its **Base Period Emissions** associated with the **CAP** pumping load in calendar years 2013 and 2014, and will reduce total CO_2emissions from its **Base Period Emissions** by 3% per year from 2015 through the end of 2031, which results in an approximate cumulative reduction of 11.3 million **Metric Tons CO_2** from **Base Period Emission** levels. **Interior** will satisfy any shortfall in the **Interior CO_2 Reduction Commitment** of 11.3 million **Metric Tons CO_2**from the **Base Period Emission** levels no later than December 31, 2035.

B. Before January 1, 2032, **Interior** will determine whether, and if so under what conditions, the **Interior CO_2 Reduction Commitment** period should be extended, considering best available scientific information regarding climate change at that time.

C. **Interior** will meet the emission reduction goals established in **Section** II.A of this **Appendix** by accruing **CRCs** annually as described in **Section** II.D, and retiring the necessary **CRCs** at the end of each compliance period, as described in **Section** II.E.

D. Accrual of **CRCs**

1. **Interior** will accrue one **CRC** each calendar year for:

a. each **Metric Ton** less than one thousand **Metric Tons CO_2** that is emitted from the **CAP Dedicated Generation** for every **GWh** produced by that generation in that year; for example:

i. a solar generator serving the **CAP** pumping load that generates one **GWh** with zero **CO_2** emissions would accrue 1,000 **CRCs**;

ii. a combined-cycle natural gas generator serving the **CAP** pumping load that generates one **GWh** and emits 400 **Metric Tons CO_2** would accrue 600 **CRCs**;

iii. an **Advanced Coal** plant serving the **CAP** pumping load that generates one **GWh** and emits 450 **Metric Tons CO_2** would accrue 550 **CRCs**;

iv. an efficiency improvement at a coal plant serving the **CAP** pumping load that reduces the emission rate from 1,000 to 900 **Metric Tons CO_2** per **GWh** would accrue100 **CRCs** per **GWh**.

b. each **Metric Ton** of emission reductions from **Qualifying Projects**. The amount of the **CRCs** for **Qualifying Projects** shall be the annual difference between the **CO_2** emissions from the **Qualifying Project** and the **CO_2** emissions resulting from an equal amount of **Generic Power**;

c. each **Offset**; and

d. each unused, documented reduction (e.g., allowances or credits) obtained by **Interior** from another program that achieves real, measurable, permanent, and verifiable reductions of **CO_2** emissions over time.

2. **CRCs** shall accrue after December 31, 2012.

3. For any electric generating facility that is awarded **RECs** associated with its electricity production, emission reductions associated with that facility will only be recognized in the accrual of **CRCs** if the **REC** associated with that production is or will be retired by **Interior.**

4. **CRCs** do not expire and may be used at any time unless and until they are retired to demonstrate compliance with the **Interior CO_2 Reduction Commitment**.

5. **Interior** may claim **CRCs** from **Qualifying Projects** as part of the **Interior CO_2 Reduction Commitment** if **Interior** has the exclusive right to claim **CO_2** reductions resulting from the **Qualifying Project.**

E. Retirement of **CRCs** to achieve $\mathbf{CO_2}$ emission reduction goals.

1. **Interior** will demonstrate the achievement of the $\mathbf{CO_2}$ emission reduction goals of this **Section** by the retirement of **CRCs**. **Interior** shall first retire **CRCs** on or before July 1, 2018 for the 2013 through 2017 period, and shall subsequently retire **CRCs** on or before July 1st every 5 years thereafter for each preceding 5-year period ending with 2031. If necessary to eliminate any shortfall in achieving its $\mathbf{CO_2}$ **Reduction Commitment**, Interior shall retire additional **CRCs** on or before December 31, 2035.

2. **Interior** will retire on the compliance dates set forth herein one **CRC** for each **MWh** of the **CAP** pumping load during that compliance period, less its **Base Period Emissions** reduced by the percentages required throughout that compliance period, as set forth in **Section** IIA of this **Appendix**. Specifically, at the end of each compliance period, **Interior** will retire the cumulative **CRCs** required for each year of that period. In each year, the **CRC** retirement obligation equals the amount expressed by the following equation:

$$CRC_{retired} = L_y - E_b(1 - R_y)$$

Where,

y = year (2013. 2014. ... , 2031)
L_y = **CAP** pumping load (**MWh**) in year y multiplied by 1.0 **Metric Ton** $\mathbf{CO_2}$ per **MWh** **[Metric Tons]**
E_b = **Base Period Emissions [Metric Tons]**
R_y = the reduction required in y (e.g. 0.00 in 2013 and 2014, 0.03 in 2015, 0.06 in 2016, 0.09 in 2017, ... , 0.51 in 2031)

3. **Interior** may satisfy a **CRC** retirement shortfall for a compliance period by retiring in the next compliance period an additional amount that is not less than the shortfall, plus all the **CRCs** that are to be retired for that next period.

F. **Continuing Efforts.**

1. As part of the **Additional Obligations of the Parties** described in **Section** VII of the **Agreement**, EDF, WRA, **Interior**, and any other **Party** that elects to participate shall meet on or before October 15, 2013, and at least semi-annually through calendar year 2015 to share information and individual comments on any aspect of the implementation and administration of **Interior's** $\mathbf{CO_2}$ **Reduction Commitment**. After 2015, these parties shall continue to meet as necessary to effectively administer the **Interior** $\mathbf{CO_2}$ **Reduction Commitment**.

2. **Interior** will consider mechanisms to compensate for shifting emissions responsibility associated with reduced **Reserve Energy** sales that increase **Surplus Energy** sales.